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ASSESSMENT OF THE POTENTIAL FUTURE MARKET IN SWEDEN FOR HYDROGEN AS AN ENERGY CARRIER

Study prepared for the
International Energy Agency

by

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Final report
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1. SUMMARY

1.1 Background

The aim of the study is to establish the present market for hydrogen in Sweden and to assess the prospects for a large-scale introduction and exploitation of hydrogen during the period 1985 - 2025 as a chemical feedstock and as an energy carrier in the energy system of the country. In doing so, the present prevailing political, social and technical conditions are taken into consideration and extrapolated to provide probable future trends. The market shares are weighted with special attention to competing alternative energy carriers, environmental restrictions, institutional conditions and independence of raw material imports.

The market study is an integral part of a series of similar studies carried out by nine Western countries within a special project group of the International Energy Society. The common framework and rules of this group are therefore consistently applied, including a special fuel cost scenario for primary fossil fuel sources.

1.2 General assumptions and fundamentals

The market analysis is performed within three different energy scenarios which all have as a background an economical scenario assumed to be valid for the period 1978 - 2025. They are regarded as being both plausible with regard to the present Swedish policy and in line with recently presented economical prognosis. They can be described briefly as

- an alternative based on nuclear energy,
- an alternative based on renewable indigenous energy sources,
- an alternative based on the present energy picture with free access to imported natural or synthetic fuels.

A number of restrictions are adopted in order to limit the possible energy scenarios under discussion. The most important are:

- Coal will only be imported in limited amounts and will be of small importance as an energy carrier throughout the period.
- Fusion and solar power will not reach their commercial break-through before the end of the period. The same is valid for geothermal power and wave power from the sea.
- The import of crude oil and oil products attains its maximum around 1990, decreases slowly up to 2005 and is of negligible importance in 2025.

All cost calculations are made in 1978 Swedish crowns (cr) or US dollars, applying a real interest of 4 %. Inflation is thus assumed to be zero. The mid-term exchange rates for 1978 have been chosen for the transfer of foreign cost figures to Swedish crowns with 1 US $ = 4.40 cr.

The price of alternative energy carriers applied in the demand sectors is equal to the production cost (import price), with costs for storage, transmission and distribution - if applicable - being added. Profits, taxes or subsidies are always excluded. No credit is allowed for by-products.

The high heating values (HHV) of hydrogen as well as of alternative energy carriers are generally applied.

1.3 Economical background scenario

A fundmental problem in a study like this is how to give a realistic description of the development of society over the next 50 years. A very brief scenario technique has been used in order to estimate roughly the future energy demand in sectors of current interest. Their anticipated growth rates, specified in Table 1-1, presuppose a heavy energy conservation programme.

The resulting energy demands are summarized in Table 1-1. The development of the production volume during the period is specified in Table 1-2. No assumptions have been made concerning changes in the production mixture etc.

Table 1-1

Energy demand scenario, TWh and PJ.

	1975		1985		2005		2025		Growth
	Twh	PJ	TWh	PJ	TWh	PJ	TWh	PJ	% per year
Industry	165	594	183	659	226	814	278	1001	1.05
Transportation	75	270	81	292	93	335	108	389	0.73
Other services (excl. residential)	70	252	75	270	87	313	101	364	0.73
Residential	80	288	81	292	82	295	84	302	0.10
Total demand	390	1404	420	1512	488	1757	571	2056	0.77
Losses	25	90	35	126	55	198	80	288	
Total energy supply	415	1494	455	1638	543	1955	651	2344	0.90

Table 1-2

Development of the Swedish production volume (in relation to the year 1975)

	1975	1985	2005	2025	Growth % per year
Industry	1.0	1.18	1.63	2.25	1.6
Transportation	1.0	1.18	1.63	2.25	1.6
Other services (excl. residential)	1.0	1.18	1.63	2.25	1.6
Residential	1.0	1.08	1.28	1.50	0.8

A serious drawback with this type of scenario technique is that the national economy is not properly taken care of.

Table 1-3 gives a summary of some important economical parameters, which have been chosen for inclusion in the study. It should, however, be emphasized that it is not clear whether or not the development given in Table 1-3 is completely consistent with the development given in Table 1-1.

Table 1-3

Assumed economical parameters.

	G$ (1978 years value)		
	1985	2005	2025
Population (millions)	8.3	8.2	7.8
GNP	98	135	185
Private consumption	49	56	65
Public consumption	27	33	40
Gross investments	19.3	24.5	31
Comm. & industry	16	21	28
of which industry	3.9	4.8	5.9
Public authorities	3.1	3.3	3.5

1.4 Energy scenarios

Three different energy scenarios of a probable nature have been developed in order to illustrate the competition between hydrogen and alternative energy carriers. The three scenarios can briefly be characterized as follows:

Scenario A:

HYDROGEN - NUCLEAR ENERGY

Hydrogen is produced by electrolysis or by thermochemical methods (high temperature reactors). Electricity is the main competitor to hydrogen.

Scenario B:

HYDROGEN - RENEWABLE ENERGY SOURCES

Hydrogen is mainly produced by chemical, photochemical or biochemical conversion. Electrolysis is also conceivable. The most important competitors to hydrogen are methane, methanol, ethanol and other fuels based on biomass.

Scenario C:

HYDROGEN - NATURAL GAS AND IMPORTED SYNTHETIC FUELS

In this scenario, the "traditional" oil import has more and more been replaced by an import of gas and synthetic fuels produced from coal. The competitors to hydrogen are synthetic petrol and synthetic "natural" gas (SNG). In scenario C, it is assumed that a pipeline system for natural gas has been built during the period 1980 - 2000. The pipeline network is supposed to cover a number of "energy heavy" regions in the country.

The energy demand according to the economical scenario has been used as the basis for the work. The energy balances given in the final scenario descriptions do not include the production and consumption of hydrogen. They rather describe the "background" energy market in which hydrogen has to compete. The final energy balances according to the market evaluation with hydrogen included in the system are given in Chapter 16.

The total energy supply in the three scenarios is summarized in Table 1-4.

Table 1-4

Total energy supply in PJ.

	Scenario A		Scenario B		Scenario C	
	2005	2025	2005	2025	2005	2025
FUELS						
Uranium	1692	2974	646	646	682	682
Coal & coke	141	141	219	229	130	130
Light fuel oil & Diesel	143	0	83	0	104	86
Heavy fuel oil	216	78	137	78	596	699
Petrol & jet fuels	119	39	119	39	119	39
Natural gas & SNG	-	-	-	-	162	237
In situ wood fuels	150	158	140	140	155	155
Synthetic fuels	40	66	-	-	70	236
Peat	-	-	212	367	-	-
Biomass	-	-	389	998	-	-
	2501	3456	1945	2497	2018	2264
DIRECT ELECTRICITY (based on renewable sources)						
Hydro	256	256	256	256	256	256
Wind	44	64	60	110	40	64
	300	320	316	366	296	320
TOTAL (PJ)	2801	3776	2261	2863	2314	2584
(TWh)	778	1049	628	795	643	718

1.5 Production

After an introductory summary of the general properties of gaseous, liquid and solid hydrogen, a broad survey is given of the large-scale production methods of hydrogen which are already commercially adopted, are under development for commercial application or have been proposed as potentially possible. The water splitting reaction serves as the main source of hydrogen, but in a few cases additional hydrogen is obtained from the heating medium, biomass or other hydrocarbonous compounds. Other primary or intermediary energy or heat sources conceived are nuclear and solar power, coal and electricity.

Process patterns for the different production methods are given, advantages and disadvantages are discussed, capital investments and operating costs are calculated, and safety and environmental aspects are summarized. The results obtained are used to evaluate the potential possibilities for the indigenous manufacture of hydrogen in a reference plant with an annual capacity of 0.14 Mton H_2.

Electrolysis is shown to be the most likely method to be applied for the large-scale production of hydrogen in Sweden. According to the demand forecast, the first production plant of the reference size can be expected to be taken into operation in the late nineties at the earliest. A probable choice for the first generation of plants will be solid polymer electrolysis (SPE) which will probably be sufficiently developed at that time to be applicable for this purpose, and which according to our cost calculations has competitive advantages over advanced alkaline electrolysis. A second generation of plants may possibly use high temperature electrolysis in oxide systems instead, being adopted first towards the end of the period.

Biomass, peat and organic wastes are indigenous fuels which can be used as raw materials for hydrogen production. Rough calculations, which are subject to great uncertainties, show that the production cost is likely to be slightly less than for electrolytic hydrogen. If this is the case, these fuels are a probable choice in scenario B. The commercial application of direct thermal or closed thermochemical water splitting appears more far-fetched but might be possible at the end of the period. The expected costs are of the same magnitude as those above, i.e. 14 ± 2.5 \$/GJ H_2. Photochemical methods, bioconversion and the application of high energy radiation are all highly improbable production methods, either due to difficult technical problems or to a very unfavourable economy.

Table 1-5 summarizes production costs for gaseous hydrogen (GH_2) according to alternative routes. Conventional methods, i.e. steam reforming of natural gas (NG) and coal gasification, have been included for comparison. Costs are also given for alternative energy carriers. Their production methods have been briefly surveyed.

Table 1-5

Production (import) costs of energy carriers.

Energy carrier	Costs $/GJ		
	1985	2005	2025
Natural gas	2.72	5.22	8.69
Synth. natural gas	3.57	5.34	7.73
Petrol	5.05	8.30	13.95
Synth. petrol	8.86	11.6	14.1
Methanol (import)	6.82	9.77	11.8
Methanol (biomass)	12.5	13.2	13.65
Electricity	6.36	8.86	12.27
GH_2 (electrolysis)	9.65	11.6	14.1
LH_2 (electrolysis)	12.05	14.7	18.2
GH_2 (biomass)	9.77	10.68	11.6
GH_2 (steam reforming)	4.45	7.80	12.4
GH_2 (coal gasif.)	5.07	6.25	7.95

1.6 Large-scale storage

In the event of hydrogen being used as a main energy carrier in a future energy supply system, large storage capacities will be necessary in order to neutralize differences between production and consumption. A survey is given of storage methods which are judged to be applicable in Sweden. Technical solutions are sketched, and their investment and operating costs are calculated. The concepts which are discussed are in part based on concepts currently being considered for the storage of LNG.

Hydrogen can be stored as compressed gas or in liquid form at very a low temperature, -253°C. In Sweden, it is anticipated that the following storage alternatives will be potentially possible:

- underground, in gaseous form, in extremely large, geologically formed reservoirs (aquifers).
- underground, in gaseous or liquid form, in large rock caverns,
- underground, in gaseous or liquid form, in large containers located in rock caverns,
- above ground, as liquid, in large, cryogenic containers.

Underground storage

Suitable formations for geological storage can be expected to be found at many places in Sweden, especially in Skåne in southern Sweden. In regions where conditions for geological storage do not exist, there are good chances of finding hard rock convenient for excavated rock caverns.

Storage of hydrogen in liquid form has been considered conceivable in:

- unlined, uninsulated rock caverns,
- unlined rock caverns with heavy thermal insulation,
- concrete-lined rock caverns with heavy insulation,
- containers located in unlined rock caverns.

Storage of liquid hydrogen in rock caverns, whether lined or unlined, insulated or uninsulated, is an extremely complex technical problem, judging by the difficulties which have been met by engineers and researchers during the development of methods for storage of liquefied natural gas in storage facilities of this type.

Comprehensive research, development and design work must be carried out before commercial underground storage facilities for hydrogen can be brought into operation.

Above-ground storage

Large-scale storage of hydrogen can be done

- as a gas at high pressure in containers with pressures up to 100 MPa,
- as a liquid at low temperatures in double-walled spherical containers,
- as a solid in the form of hydrides.

Only the second method is economically competitive for the present.

Table 1-6 summarizes the storage costs in facilities connected to a reference plant for hydrogen production. It is assumed that a storage volume of 1/10 of the annual capacity, 0.14 Mton, is required. The costs for the storage of alternative energy carriers - in appropriate columns - are included for comparison.

Table 1-6

Storage costs calculated as 1/10 of the real annual costs, \$/GJ.

Storage method	GH_2	NG	Petrol	Methanol
Geological	0.18	0.064		
Unlined, uninsulated rock cavern	0.38	0.125	0.01	
Lined, insulated rock cavern (liquid)	0.27			0.04
Unlined, insulated rock cavern (liquid)	0.23	0.073		
Tanks above ground (liquid)	0.22	0.07	0.023	0.048

1.7 Transmission

Three transmission alternatives are described and compared, namely the transmission of gaseous hydrogen by pipeline, of gaseous hydrogen in bulk and of liquid hydrogen in bulk.

Pipeline transmission of hydrogen gas has been carried out for decades, and the technology is well established. It seems possible to convert a natural gas pipeline for the transmission of hydrogen gas, though the amounts of energy transmitted will be somewhat lower.

The cost of a new hydrogen pipeline has been estimated by comparison with cost figures for a recently proposed natural gas pipeline in southern Sweden. Transmission over a distance of 200 km will cost 0.12 \$/GJ at a gas pressure of 6 MPa. If low cost steel pipes in combination with a lower gas pressure are chosen, the cost will increase proportionally but will not exceed 0.27 \$/GJ, which is still a low figure compared to other modes of transmission.

The cost of transmission of hydrogen gas by lorry has been estimated to be 7.7 \$/GJ (100 km), but this will apparently only be possible for moderate amounts of gas, as otherwise the traffic load on roads will be prohibitive.

Transmission of liquid hydrogen by lorry or rail is today carried out on a very limited scale. The necessary technology is developed, and a transmission system can be built up with investments which are moderate and adjusted to the capacity of the system. The capacity will, however, reach an upper limit when the number of vehicles on roads and railways interferes with the general traffic flow. A cost of less than 1.2 \$/GJ is anticipated for a transmission distance of 100 km.

Special safety precautions must be observed when hydrogen is transmitted as a gas or liquid. Most of the problems involved appear to be solved. Even transmission of liquid hydrogen in bulk by lorry or rail is permitted today, with the restrictions which safety demands.

Transmission costs for GH_2 in a pipeline and for LH_2 by lorry or rail are summarized in Table 1-7 and compared to those of alternative energy carriers.

Table 1-7

Transmission costs in $/GJ.

Energy carrier	Transmission distance, km		
	100	200	500
GH_2 (pipeline)	0.14	0.23	0.55
LH_2	1.14	1.60	2.50
NG and SNG (pipeline)	0.09	0.16	0.30
Petrol	0.12	0.40	0.50
Methanol	0.23	0.32	1.02
Electricity	1.64	1.82	2.45

1.8 Chemical industry

According to available statistics and to direct information obtained from the parties concerned, hydrogen currently has a very limited use as a raw material or as a fuel in Swedish process industries. The annual consumption as a raw material is about 35 000 tons, and this is mainly used for the synthesis of ammonia and various organic compounds, for the hardening of fats and for petroleum refining. Most of the captive hydrogen generated in petroleum refining operations is consumed for heating purposes (160 000 tons annually).

The market investigation performed shows that the consumption of high-energy gases (NG, GH_2 or a mixture of these) as feedstocks is unlikely to increase significantly during the period. If specially favourable conditions are created for ammonia and methanol industries, for example by a national policy providing a strong element of stimulus or protection, or by a future large-scale exploitation of Swedish shale deposits, the use of hydrogen could exceed 0.2 Mton in about 25 years' time. In an open, non-protected economy, this is not likely to be the case. The pipe grid for NG/SNG/H_2, which is assumed to be built in the nineties according to scenario C, would constitute a favourable pre-requisite for ammonia/methanol plants, particularly towards the latter part of the period studied, when gasification plants based on bio-materials could also have been phased into the supply system. It is, however, less probable that pure hydrogen would be fed into the grid in anything but marginal quantities.

The total consumption of fuels in chemical process industries is expected to be almost doubled in 50 years. A large part of the market increase may be covered by merchant high-energy gases where GH_2 is one alternative. Penetration of the market will be particularly favoured if a national gas piping system as in scenario C is introduced. It is anticipated here that the maximum share of this market gained by high-energy gases will be 37 % in scenario C and 12 % in scenarios A and B, the total annual fuel consumption being 176 PJ.

The results of the assessment are summarized in Table 1.8. The variations in the data given are due to the policy-dependent production of ammonia and methanol and to the competition between GH_2 and NG/SNG as a heat source, as has been discussed above.

Table 1-8

Hydrogen consumption in the chemical sectors, PJ/year.

Year	1978	1985	2005		2025	
Scenario		A, B, C	A, B	C	A, B	C
Sector						
Chemical	4.3	4.8	2.4-4.8	2.4-4.8	4-11	4-11
Petrochemical	1.5	2.9	4.5	4.5	3	3
Syn. fuel		0-4.3	0-18	0-18	0-18	0-18
Ind. heating	23.5	24	24-34	24-54	11-32	11-76
Total	29.3	31.7-36	31-61	31-81	18-64	18-108

1.9 Metallurgical industry

The structure of the Swedish iron and steel industry has undergone a rapid change during the seventies. The world-wide stagnant demand for raw steel and refined steel products and the simultaneously increasing costs and decreasing product prices have led to a concentration of the production to fewer and larger plants. This trend is still continuing.

In Sweden, most of the reduction of iron ore is done in blast furnaces. Coke is the reducing agent generally used, and it is either directly imported or domestically produced from imported coal of an expensive quality.

A survey is given for the material and energy balances of present production methods. Capital and operating costs are accounted for and related to different parts of the production processes. The theoretical basis for carbon reduction is briefly described and compared to that of other possible reduction agents, particularly hydrogen.

Many processes using either pure GH$_2$ or a combination of GH$_2$ and carbon have been proposed and tested on a pilot plant scale for the reduction of iron ores of various types. Some of the most important processes are illustrated in simplified flow diagrams, and are briefly described and cost-calculated. Their advantages and disadvantages are discussed in relation to the conventional carbon process. Only the Wiberg process is judged to be competitive and therefore likely to be applied in large-scale production.

Some new processes are also considered. The most promising ones are injection smelting reduction and hydrogen plasma reduction. The former is not hydrogen-based but is judged to be one of the major competitors to future hydrogen processes. In the fuel cost scenario of this study, smelting reduction in combination with fuel gas production appears to become profitable at the end of the period studied, even if the value of the raw steel produced is set at zero.

Hydrogen based plasma reduction has the advantage that it is a very rapid process. Hence, small reactors could be used and run intermittently. The total reduction cost is, however, higher than for blast furnace reduction or for the Wiberg process. Thus hydrogen based plasma reduction appears to be of interest, only if the general structure of steel production should change towards small intermittently working units integrated with further manufacturing. Whether the present trend towards larger production units will be replaced by such a change depends on the future demand for product types and the availability of raw materials. It will be favoured if the present heavy taxation of the use of labour is displaced by a new system where taxation is mainly based on other production factors.

The hydrogen demand anticipated here is based on the assumption that shortage of raw materials and fuel, increased demand for flexibility in the production and a trend towards day-time production will favour hydrogen based plasma reduction. This change is expected to start around 1990 and to be initially competitive for some special products. In 2025, it is assumed that about one half of the total steel production will be produced in small plasma reactors.

The total demand for steel is assumed to be almost the same in 2025 as it was in 1974. A substantial part of the steel produced today is turned to scrap before the final manufacturing step. With a steel production better adjusted to finished products, less scrap is obtained. The demand can therefore be met with a somewhat smaller production (5 Mt steel in 2025).

In a scenario based on these assumptions, the anticipated demand for hydrogen as a reducing agent in iron ore reduction is

	1985	1995	2005	2015	2025
kton	-	15	43	73	100
PJ	-	2.1	6.2	10.4	14.5

Hydrogen may also be used as a reductant in the production of metals other than iron. Such uses of hydrogen are only likely to occur to an extent which is smaller than the margin of error in the above estimate of the need for hydrogen in steel production.

1.10 Peak power production

In Sweden, electric energy today is produced for peak power purposes by condensing, Diesel or gas turbine plants. Pump power stations are regarded as a more economical means to cover the future demand. Hydrogen can also be used for this purpose by being converted to electricity in conventional gas turbines or in fuel cells. Such plants can be of the storage or the non-storage type.

A complete breakdown of costs as a function of the utilization time was performed, comparing hydrogen driven stations with seven conventional types, including pump power. The fuel cell efficency was assumed to be 60 % in 2025 and the hydrogen gas turbine efficiency to be 50 %. Environmental and societal effects were also taken into consideration.

The result shows that fixed annual costs are of the same magnitude with a few exceptions, but that running costs for pump power are much lower than those for the other methods which are mutually more comparable. Under the assumptions valid for this study, it is concluded that hydrogen peak power cannot compete with pump power unless its efficiency can be raised above that of pump power, i.e. 80 %, which is impossible to expect during the period studied. Environmental and societal effects cannot compensate for the very large economic disadvantages.

Except for very special purposes and hence in limited amounts, hydrogen cannot be expected to be used for peak power production during the period studied.

1.11 Residential and commercial heating

After some introductory notes about the total Swedish consumption of energy for residential and commercial heating, technical aspects of the application of hydrogen gas as a heat source, either by direct combustion in an atmospheric burner or as a fuel for heat pump engines, are discussed and compared to conventional or advanced alternative heating systems. Both systems for private houses and for large residential or commercial buildings are taken into consideration, and include in the latter case also district heating.

Residential heating presupposes that a national gas piping system has been constructed, covering large population centres and similar to that prescribed in scenario C. Hydrogen gas must also be accepted as a safe and reliable heat source by the consumer and by society, and must also be competitive to other heating mediums and methods. Heating with evaporating LH_2 is out of the question. Hydrogen for industrial heating, on the other hand, can be supplied from an internal or local grid system.

Suitable techniques for the application of hydrogen burners and heat pumps can be expected to be fully developed in the nineties. It should be possible to overcome the safety problems which arise. Heat pumps have the advantage that they generate more useful heat than was originally supplied by the fuel. They have also been shown to be somewhat more economically advantageous than burners.

For all the heating alternatives studied, a complete cost breakdown has been made, comprising capital costs, fuel costs and specific energy costs. Energy sources such as oil, NG, methanol, electricity and biomass were compared with hydrogen. In all cases studied, the cost of energy was found to be high compared to that of the equipment, which favours the use of heat pumps.

The following conclusions have been drawn:

- In scenario A, hydrogen cannot compete with the low costs of electric heat pumps which are expected to become one of the major heating devices.
- In scenario B, hydrogen heating is an interesting alternative with lower costs than those of other permitted methods. The market share is estimated to be 5 PJ in 2005 and 50 PJ in 2025 because of the slowness of the introduction process.
- In scenario C, hydrogen can hardly compete with much cheaper SNG which in the scenario is allowed to be imported in unlimited amounts and has a finished distribution system. Governmental actions such as special taxes due to environmental considerations could change this picture.

1.12 Transportation

First, a thorough survey is made of technical aspects in the application of hydrogen fuelled propulsion for land, air and sea transport. The emphasis is put on road vehicles as the international air traffic to Swedish airports most likely will continue to be too limited to support a transfer to LH_2 fuelling within the investigated period. For sea transport as well as railway traffic, conventional or new alternative fuels carry advantages which only allow a very limited introduction of hydrogen.

Technical systems for the conversion of Otto or Diesel engines to hydrogen fuelling are described and compared with each other and with electric propulsion. A similar comparison is made for various proposed storage systems for LH_2 and GH_2. Safety factors and environmental emission are also discussed and taken into consideration in judging the competitiveness of the compared alternatives and the probable trend of development. Hydrogen is finally judged to be one of several equally possible ways of solving the future vehicle fuelling problem. The introduction will most likely be made by adapting GH_2 fuel to reciprocating piston engines, but at a later stage of the period studied, fuel cell powered vehicles are expected to be fully developed and will successively increase their market share. Because of its development potential, a hydride tank storage system is considered as the most promising storage method.

The present fuel distribution and servicing structure is analysed in order to identify those transport modes and corresponding infrastructures which from an economical and safety point of view are most well adapted to a future large-scale use of hydrogen. A system based on self-service station modules with vehicle servicing capabilities is judged to be most advantageous and is used as a reference case in the economic assessments. Hydrogen is supplied to the fuel stations through gas pipelines.

An approach deviating from that applied in the other market sectors has been used for the assessment of the future transportation market. Five different alternatives have been suggested with different mixtures of propulsion and fuelling systems, which are all judged to be very probable within given scenarios. The total costs to society of each alternative have been evaluated as a function of the time span and related to a "spontaneous" development case which represents an extrapolation of the present conventional technology, with battery powered electric vehicles for town traffic being slowly introduced into the market in the beginning of the nineties. The evaluation comprises all types of road traffic, car manufacturing and the complete fuelling system. For the case with a rapid market penetration of hydrogen driven cars, the annual extra costs reach a maximum of about 0.6 G$ in the middle of the period and become negative during the last 10 years. A similar methanol case has a similar development. On the other hand, battery driven cars give rise to successively increasing savings from the time of their introduction.

It is evident from the above that in scenario A, where the supply of electricity is ample, hydrogen can hardly compete with electricity. In scenario B on the other hand, hydrogen appears to be advantageous but competes with almost equally favourable methanol. Even in scenario C where petrol is available in unlimited amounts, a slow introduction of hydrogen might lead to economic advantages.

A fraction of about 30 % of the Swedish transport energy is consumed by a heterogeneous group of vehicles, for instance international and military transports, agricultural and lumbering machinery and small boats. These categories are not likely to convert to new fuel systems at all during the period and are therefore not included in the cost calculations of the alternatives conceived.

For each of the chosen alternatives, the anticipated total fuel consumption is summarized in Table 1-9. The figures given include all types of land, sea and air transport. The petrol column represents all conventional petroleum fuels.

Table 1-9

Fuel consumption in the transport sector, PJ.

Alternative	2005				2025			
	Petrol etc.	Methanol	GH_2	Electricity	Petrol etc.	Methanol	GH_2	Electricity
El. battery	348			20	317			31
High H_2	265		71	17	150		135	28
Methanol	253	107		15	132	182		24
Spontaneous	387			16	360			27
Low H_2	380		4	15	330		16	25

1.13 Materials problems

The nature of hydrogen damage to structural materials in hydrogen energy systems has been examined, identified and defined. The operating mechanism/s of the said damage may be classified into the following three broad categories:

- internal reversible hydrogen embrittlement,
- hydrogen environment embrittlement,
- hydrogen reaction embrittlement.

These mechanisms may act in a specific manner, alone or synergetically, on specific materials and under specific conditions. This specific nature of the hydrogen attack has been briefly touched upon. Certain precautionary measures are suggested as regards materials selection and workshop practices in component manufacture.

Material properties required for various components in a hydrogen energy system (generation - storage - distribution) are briefly discussed, and some pertinent laboratory practices for correct material evaluation are enumerated. Candidate materials of existing commercial varieties and their respective mechanical integrities under the expected conditions of operation are presented with extensive charts, tables and figures. Although the material problems as a whole in hydrogen energy systems lead to about the same demand on component materials at all stages, from production to applications, there are certain special features of metal-hydride and liquid hydrogen storage systems. The particular demands on materials made by such systems are accounted for separately, and the required material properties are specified.

Finally, conclusions are drawn from the existing state of knowledge in this field, and certain suggestions are made as regards the future course of action for materials research - new synthetics and/or old-modified. It is quite possible that an existing network of natural gas pipelines may be integrated into a hydrogen distribution system, provided that the economic of a somewhat lower gas pressure is not adverse and the integrity of weld joints is revalidated under a hydrogen atmosphere.

1.14 Safety and protection

The chapter gives a survey of problems of a more general nature when handling gaseous or liquid hydrogen. The special problems which arise during production, storage, transportation and application of hydrogen are discussed in the appropriate special chapters.

The physical and chemical properties of hydrogen relevant to safety and protection are listed and compared to those of alternative energy carriers, particularly NG and petrol. Regulations and recommended guidelines are briefly touched upon and related to necessary safety practice and suitable protection measures. Future safety research needs are outlined.

Consideration of future hydrogen applications reveals no insurmountable problems in the industrial and commercial market, as long as prescribed safety rules are rigorously followed and the equipment is handled by well trained personnel. Excellent safety records have been maintained during the long use of gas piping systems in Germany and the US as well as by NASA in its use of vast quantitities of LH_2 in the American space program. Safety problems may, however, arise with transport and in residential applications where the general public could experience a more direct contact with hydrogen. This is particularly the case if LH_2 is used as a common car fuel. GH_2, on the other hand, has been in common use for a long time as an admixture to town gas without either perceptible negative consequences for society or public objections.

However, public perception of the safety of hydrogen may become one of the major obstacles to a transition to a hydrogen economy. As a result of the impression of the greatly over-dramatized Hindenburg-Zeppelin accident, hydrogen is in public eyes identified with a major catastrophe and therefore regarded as an exceptionally dangerous substance.

There is no point in denying the danger implicit in the widespread use of hydrogen. Compared to NG, GH_2 is much more prone to leakage, can be ignited by extremely low quantities of energy, and is flammable and explosive over a wide range of hydrogen-air mixtures. In liquid form, its low temperature liquefies any air in contact with it, which produces highly explosive mixtures. Furthermore, the gas is colourless and odourless, and burns with an almost invisible flame.

The damning list of negative properties is partly counterbalanced by the high buoyancy and diffusitivity of GH_2. A leak therefore seldom leads to a concentration sufficient to sustain ignition and, unlike petrol, methanol and NG, hydrogen very rapidly departs from the scene of spills and leaks.

1.15 Health, environmental and societal implications

All energy carriers which are expected to provide Sweden with energy in the future are associated with health and environmental risks. Great consideration must be given to these risks in the design of the future energy policy.

An attempt has been made to quantify the total societal implications arising from the use of all energy carriers considered here by carrying out a comparative risk analysis of different ways of producing energy. The analysis has been carried out for the complete fuel cycle from the original production (mining) up to the final application. Risk factors were calculated for health, other environmental aspects and societal implications. The risk factors obtained were quantified as a cost by multiplying them with a specific cost factor which is directly related to the unit of the risk factor.

The basic data were mainly obtained from published reports but they are believed to be also applicable for Swedish conditions. For the present, no method has been found of transforming social implications into cost figures of any reliability.

The most important conclusion to be drawn from the study is that the risk from non-conventional energy sources appears to be significantly higher than that from conventional sources. The lowest health and environmental costs are obtained for nuclear electricity, natural gas and hydrogen. This is in agreement with some other investigations where the risks of hydrogen have been compared to those of some other fuels, mainly natural gas and petrol.

Table 10-1 summarizes cost factors obtained for the principal alternative energy carriers of this study.

Table 1-10

Risk costs for alternative energy carriers in cent/GJ in 2025.

Energy carrier	Health cost	Other env. cost
Natural gas	1.15	0.25
Petrol	21.5	2.3
Methanol		
from coal	180	3.2
from biomass	400	2.7
Electricity, nucl.	3.4	0.25
GH_2, coal gasification	30	3.2
electrolysis, nuclear el.	3.4	0.25

1.16 Conclusions

For each of the threee scenarios A - C, the total demand for hydrogen according to the market analysis performed is given in Table 1-11. The sectors specified are those which have been agreed upon within the IEA Study Group. It must be emphasized that the uncertainty in all the figures for 2005 and 2025 is very large and that they can only be regarded as reasonable estimates on the basis of the assumptions given in the introductory chapter and/or discussed in the sections on applications. Where the figures in the columns are given as ranges, these depend on policy-dependent factors in the chemical industry or the choice of alternative in the transportation sector.

On the basis of the maximum demand values for merchant hydrogen in Table 1-11, the average annual investment requirements have been roughly estimated for the time periods 1995 - 2005 and 2005 - 2025. Only investments that are necessary in order to achieve the anticipated hydrogen economy are included. Investments resulting from normal industrial capital renewal are disregarded. The capital demand is largest in scenario B, where hydrogen is supposed to be produced from biomass, and is on average 0.85 - 1.0 G$ during the period.

In scenarios A and C, where hydrogen is electrolytically produced, the average capital demand is between 0.125 and 0.35 G$ except for the time period 1995 - 2005 where in scenario C about 0.6 G$ could be required. A slower introduction of GH_2 into the assumed existing high-energy gas system should appreciably reduce this figure.

In all the scenarios, the required investment capital will thus be less than 4 % of the available national gross investment sum according to the assumed economic scenario.

Table 1-11

The Swedish hydrogen market in PJ/year.

Market sector	Actual market 1978	Estimated demand						
		1985	2005			2025		
		A,B,C	A	B	C	A	B	C
Non Energy								
Chemical	3.5	5	2-8	2-8	2-8	3 - 10	3 - 10	3 - 10
Metallurgy	-	-	6	6	6	15	15	15
Energy Indirect								
Petrochemical	1.5	3	4	4	4	3	3	3
Syn.fuel	-	0 - 4	0 - 5	0 - 18	0 - 18	0 - 5	0 - 18	0 - 18
Peak power	-	-	-	-	-	-	-	-
Energy Direct								
Space heating	-	-	-	5	-	-	50	-
Process heat*	23.5	33	36 - 52	36 - 52	36 - 72	18 - 43	18 - 43	18 - 91
Ground transp.	-	-	-	0 - 71	0 - 4	-	0 -135	0 - 16
Air transp.	-	-	-	-	-	-	-	-
Total	28.5	41 - 45	48 - 75	53 -164	48 -112	39 - 76	89 -274	39 -153

* The lower figure represents internally generated hydrogen.

2. GENERAL ASSUMPTIONS AND FUNDAMENTALS

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2.1 Scope and object of the study

The object of the study is to establish the present market for hydrogen in Sweden and to assess the prospects for a large-scale introduction and exploitation of hydrogen as a chemical feedstock and as an energy carrier in the energy system of the country. In doing so, the present prevailing political, social, technical and geographical conditions are taken into consideration and extrapolated to provide probable future trends. For each of the years 1985, 2005 and 2025, the probable market demand of hydrogen is illustrated as calculation examples for those market sectors which can be expected to dominate the demand. The market shares are weighted with special attention to competing alternative energy carriers, environmental restrictions, institutional conditions and independence of raw material import.

The market study is an integral part of a series of similar studies carried out by nine Western countries within a special project group of the International Energy Agency (IEA) "Assessment of Potential Future Markets for the Production of Hydrogen from Water". The common framework and rules of this group are therefore consistantly applied. It has been thought valuable to put a certain emphasize on those points where the energy-political and geographical situation in Sweden deviates significantly from that of most of the other participating countries, as follows:

- No domestic supplies of fossile fuels.
- A very high import of crude and refined oils (ca 70 % of the total energy consumption).
- A high percentage of nuclear produced electricity (ca 25 %) which is highly controversial.
- No distribution system for natural gas. A future pipeline system can therefore, at the time of its construction, be adapted to the distribution of hydrogen.
- Highly centralized residential and industrial premises which facilitate the construction of a gas pipeline system with a high population coverage.
- A cold climate which necessitates a large energy consumption for heating purposes.
- A metallurgical industry sector which is of great significance from the point of view of employment and balance of trade.
- An alliance-free foreign policy and an independent trade policy.

The market analysis is performed within three different energy scenarios which are described in greater detail in Chapter 4. These are all based on an economical background scenario for the period 1978 - 2025, Chapter 3, which is regarded as being both plausible with regard to the present Swedish energy policy and in line with recently presented economical prognosis. The energy scenarios have been developed in the absence of a hydrogen contribution. They can be described briefly as

- an alternative based on nuclear energy,
- an alternative based on renewable domestic energy sources,
- an alternative based on the present energy picture with free access to imported natural or synthetic fuels.

2.2 Restrictions and rules due to the IEA common framework

The market survey should consider the development of demand and supply for hydrogen during the period, taking into account competition from alternative energy carriers and analysing technical, economical, environmental and safety aspects. The principal sectors to be treated are the chemical and metallurgical industry, peak power generation, residential and commercial heating, and transportation. Aspects to be studied are fuel cost scenarios, production, storage, transmission and distribution.

Cost evaluations are made according to accepted national methods of calculation and expressed in a constant 1978 currency.

The SI-system is used throughout the reports. The higher heating values (HHV) are used for all fuels and on a volume basis given at $0^{\circ}C$ and 0.1 MPa.

A price scenario for common fossil and other fuels, agreed upon by the IEA participants, is used for all evaluations. The data are summarized in Table 2-1 and expressed as the free import price to a Swedish port.

Table 2-1

Fuel price scenario in $ (1978) per GJ.

Fuel	1978	1985	2005	2025
Steam coal	1.41	1.52	2.27	3.31
Crude oil	2.50	2.86	5.01	7.64
Petrol	4.43	5.05	8.3	13.95
Jet fuel	4.80	5.48	9.0	15.05
Natural gas	2.39	2.72	5.22	8.69
Methanol	6.02	6.82	12.8	21.3
Uranium, $/g		0.132	0.274	0.519

2.3 Special restrictions for the Swedish study

A number of restrictions are adopted in order to limit the possible energy scenarios under discussion to those that are a) fully relevant within the period under review, b) technically applicable in a large scale and c) in conformity with the present general energy policy:

- Coal will only be imported in limited amounts and is of small importance as an energy carrier throughout the period. This restriction appeared to be the most likely during the initial part of the market study. However, coal is regarded today as one of the principal alternatives of primary energy for the future Swedish energy supply. The advanced state of the study has not permitted the inclusion of coal as a fourth scenario alternative.
- Fusion and solar power have not reached their commercial breakthrough before the end of the period. The same is valid for geothermal and wave power from the sea or inland lakes.
- The import of crude oil and oil products attains its maximum around 1990, decreases slowly up to 2005 and is of negligible importance in 2025.
- In at least one of the scenarios, it is assumed that a gas piping system covering the main population and industrial centres is constructed during the period 1990 - 2005.
- The production of electricity is based on nuclear, water, wind and biomass power.
- The required energy for heating and hot-water production is successively transferred from the present oil dependence to individual or long-distance heating systems based on domestically available primary or secondary energy sources.
- The future demand for large quantitites of hydrogen will be wholly covered by domestic production.

2.4 Economic evaluations

All cost calculations are made in 1978 Swedish crowns (cr) or US dollars, applying a real interest of 4 %. Inflation is thus assumed to be zero. Cost figures from earlier years are translated into Swedish currency, applying the valid exchange rate of that year, and then corrected for inflation by means of the price index series given by the Swedish Statistical Central Bureau. Unless otherwise stated, capital cost evaluations are based on a depreciation time of 10 years and applied as equal annuities, which become:

5 years' depreciation time = 22.46 %
10 "- = 12.33 %
20 "- = 7.37 %

The price of alternative energy carriers applied in the demand sectors is equal to the production cost (import price), with costs for storage, transmission and distribution - if applicable - being added. Profits, taxes or subsidies are always excluded. No credit is allowed for by-products.

The zero inflation factor, valid in all cost elements except for the fuels, is applied in such a way that regard is given to special independent factors which might directly influence the costs, for example new manufacturing technology and scale-factors, conversion of infrastructures, and additional environmental and safety measures.

The mid-term exchange rates for 1978 have been chosen for the transfer of cost figures from Swedish crowns to foreign currencies. Some rates of importance for the study are given in Table 2-2.

Table 2-2

Currency exchange rates (mid-1978).

Country	Currency	Swedish crowns
US	1 \$	4.40
Canada	1 \$	3.95
UK	1 £	8.65
Germany	100 DM	225.2
Switzerland	100 SFr	254.3
Belgium	100 BFr	14.38
Netherland	100 Fl	209.0
Japan	100 Yen	2.17

2.5 Technical fundamentals

The high heating value (HHV) of hydrogen is set at 12.77 MJ/Nm^3 (0°C, 0.1 MPa) or 142.5 GJ/ton.

It is assumed that techniques for the large-scale storage of gaseous hydrogen (GH_2) and of liquid hydrogen (LH_2) are available in the middle of the nineties. Hydride storage is also sufficiently developed to be commercially applicable within for example the transport sector. Pipeline systems can be used for the safe transmission of large volumes of GH_2.

3. ECONOMICAL BACKGROUND SCENARIO

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3.1 Introduction

It is obvious that no estimations that can really be termed forecasts can be made for the economical development of a society in 45 years' time perspective. This is also true for the development of energy consumption. New decisions must successively be taken and they will be based on the knowledge and on the level of technical development that is available at that time.

The technical development that takes place during the period from now to 2025 will undoubtedly be very large. Fundamental problems of new technologies may be solved and lead to a rapid major break-through within the period. Examples of such areas are fusion power technology and the technique for making very deep holes in the earth crust which can give access to a controlled use of the energy content of the magma.

Large sections of the energy system are, however, very slow to change. This is true for instance for power stations, which often have life times of 25 years or more. The same is also valid for a number of industries with large energy consumption, such as the paper and pulp or the steel industry. The introduction of a new (more energy-conserving) process in such industries may require an almost total reconstruction of the whole factory. The engines of motor vehicles usually require fuel of a certain quality, and they also have a considerable life time (10 - 15 years).

Other parts of the energy system are more flexible with regard to energy carriers. In a district heating system, the hot water can be produced in a number of different ways without making any problems for the final consumer. The same is also true for various ways of producing electrical energy to be fed into the electrical network.

3.2 Development of the energy demand

The long range studies issued by the Swedish Department of Economy deal mainly with the development of various parts of the Swedish economy during the next five-year period. The latest study available is from 1978 and covers the period up to 1983 (1). It also includes a separate chapter with the more distant time horizon of 1990. For the period up to the year 2025, only some alternative population developments are presented, together with some information about corresponding needs for residential houses, public services etc. The study concerning the period up to 1990 is based on the present structure of production in Swedish society. Various assumptions are made about the annual development (growth or decrease) of the production volume in different industrial sectors etc. The structure of the society of 1990 is hence not too different from that of today.

For the period after 1990 there is practically no official governmental material available that can help us to make estimations about

- the total energy demand,
- the structure of the demand sectors, which types of industries we will have, how far the energy conservation programme will progress, how the transportation sector will develop with regard to types of vehicles, volume of collective transport, etc.

In the scenario descriptions given in this study, a rather inflexible approach must be made to these matters. The level of energy consumption should be high enough to encourage a dynamic and expanding commercial and industrial life. However, the considerable potential for energy conservation in the various sectors should also be taken into account. The approach used in the study "Solar versus nuclear" (2) seems to be useful. In that study the following estimations were made (Table 3-1).

Table 3-1

Estimated growth demand in various sectors during the period 1975 - 2015 (2)

	1975 Energy		Production growth	Change in spec. energy consumption	2015 Energy	
	TWh	PJ			TWh	PJ
Prod. of goods	165	594	+ 100 %	- 20 %	264	950
Prod. of services						
transport	75	270	+ 100 %	- 50 %	75	270
others	70	252	+ 100 %	- 50 %	70	252
Residential sector	80	288	+ 40 %	- 30 %	80	288
Total demand	390	1404			489	1760
Losses	25	90			60-80	215-290
Total energy supply	415	1494			550-570	1975-2050

In 1977, the National Swedish Industrial Board (SIND) published a number of different energy demand forecasts for the period 1975 to 1995 (3). These forecasts were based on somewhat different assumptions about the growth of the production sectors, and also on different assumptions about the level of the energy conservation efforts.

In the case when the lowest economic growth rate was combined with the most massive programme of energy conservation (SIND case B), the following growth rates were predicted for the energy demand (% per year):

1974 - 1985	1985 - 1990	1990 - 1995
1.5	0.3	0.5

This case is in reasonable agreement with the "Solar versus nuclear" scenario, if a growth rate of 0.5 % per year is also used for the period 1995 - 2015.

A doubling in the volume of goods produced and in services over a 40 year period corresponds to an annual growth of about 1.75 % per year on average. Thanks to energy conservation, the corresponding growth of the energy demand is limited to about 0.75 % per year in the "Solar versus nuclear" scenario.

However, it should be emphasized that it is not possible to let the production volume grow more than twice as fast as the energy supply for an indefinite period. This would require a continuous supply of new energy conservation methods such as to reduce the specific energy demand by 10 % per ten-year period.

An important aspect which is often disregarded in long range energy studies of this kind is the change in the production structure. At present, about 60 % of the total energy consumption in the industrial sector is used for the production of pulp, paper and steel. This type of production has a comparatively low value of the factor "GNP contribution per energy unit consumed". Considerably higher values of this factor are valid in the engineering industry, for instance. Such effects are taken into account in the SIND forecasts for the period up to 1995 but for the more distant future it is very difficult to estimate possible changes in the production structure. The results of an increased level of refining in the Swedish industry (more engineering industries in relation to the size of the steel industry, more paper as opposed to pulp etc) will be that the energy consumption per GNP unit will decrease.

It can also be questioned whether or not it is a realistic approach to assume that our society can double its consumption of goods and services (in physical quantities). Certainly, some part of the increased production could be used in the developing countries for instance, but on the other hand these countries have an ambition to build up their own production capacity.

The dilemma we have to face when we choose the level of the energy demand for our scenarios lies in that

- we do not want to choose such a high growth rate for the economy that it becomes difficult to explain how the large volume of goods and services could be used in a meaningful way,

- we do not want to choose such a low growth rate so that a technical and economic decline of society might be prophecied.

As a result of these considerations a framework has been chosen for the development of production and of the energy demand according to Table 3-2. The same method of reasoning has been used as in (2) but with some changes in the estimations of the changes in specific energy consumption (cf Table 3-1).

The development of the relative production volume is illustrated in Table 3-3. The development of the energy demand at different times during the period 1975 - 2025 is given in Table 3-4.

Table 3-2

Predicted energy demand growth during the period 1975 - 2025

	1975 Energy TWh	Production growth	Change in spec energy consumption	2025 Energy TWh
Prod. of goods	165	+ 125 %	- 25 %	278
Prod. of services transport	75	+ 125 %	- 40 %	108
others	70	+ 125 %	- 40 %	101
Residential sector	80	+ 50 %	- 30 %	84
Total demand	390			571
Losses	25			c. 80
Total energy supply	415			c.650

Table 3-3

Development of production volume (by comparison with the year 1975).

	1975	1985	2005	2025	Growth % per year
Industry	1.0	1.18	1.63	2.25	1.6
Transportation	1.0	1.18	1.63	2.25	1.6
Other services (excl. residential)	1.0	1.18	1.63	2.25	1.6
Residential	1.0	1.08	1.28	1.50	0.8

Table 3-4

Energy demand scenario for the hydrogen study.

	1975 TWh	1975 PJ	1985 Twh	1985 PJ	2005 TWh	2005 PJ	2025 TWh	2025 PJ	Growth % per year
Industry	165	594	183	659	226	814	278	1001	1.05
Transportation	75	270	81	292	93	335	108	389	0.73
Other services (excl. residential)	70	252	75	270	87	313	101	364	0.73
Residential	80	288	81	292	82	295	84	302	0.10
Total demand	390	1404	420	1512	488	1757	571	2056	0.77
Losses	25	90	35	126	55	198	80	288	
Total energy supply	415	1494	455	1638	543	1955	651	2344	0.90

The figures of Table 3-4 are used as the basis for the energy scenario work which is described in Chapter 4.

There are two main reasons for the comparatively modest volume development of the residential sector:

- A stagnating population growth (1).
- The demand for an improved standard of housing is expected to grow asymtotically towards a "saturation level".

3.3. Development of the national economy

The type of scenario technique which is described in Section 3.2 and which was used in this study has a serious drawback due to the fact that the development of the national economy is not properly taken care of. The "picture" of Sweden in the year 2025 is "painted" without any consideration being given as to the real possibilities of its attainment. The need for investment capital or some other question may turn out to be a prohibitive factor that makes the projected development impossible. In other words, it is not shown how the given "final" state can be reached.

In order to get some idea of the economical balance in a society of the type discussed here, an attempt was made to estimate a possible development. The estimation is based on a scenario given in the long range study LU78 (1). The particular scenario describes a possible way for Sweden to reach a balance in its international payments by keeping down the domestic demand for goods and services. This scenario has an average GNP development of 2.8 % per year (1977 - 1983). Our scenario for the hydrogen study has an average GNP development of 1.6 % per year (1977 - 2025). In the absence of other possiblitities, the figures from the LU78 scenario describing the percentual annual changes of the various economical parameters were multiplied by the factor

$$\frac{1.6}{2.8} = 0.57,$$

which resulted in the following table (Table 3-5).

The most important parameters (expressed in Swedish crowns of 1978) for the years 1985, 2005 and 2025 are summarized in Table 3-6.

Table 3-5

Economical balance 1977 - 2025 for the hydrogen market study.

	Mcr 1977	Annual volume change % 1977 - 2025
Supply		
GNP	351 511	1.6
Import	91 524	2.1
Total	443 035	1.7
Demand		
Private consumption	189 293	0.7
Public consumption	100 925	1.0
Gross investments	71 403	1.2
Comm. & industry	59 093	1.4
Of this: industry	14 790	1.0
Publ. authorities	12 310	0.3
Stock investments	-1 300	
Balances of services and transfers	-2 407	8.5
Export	85 121	4.1
Total	443 035	1.7

Table 3-6

Some important economical parameters.

	Gcr (1978 years value*)		
	1985	2005	2025
Population (million)	8.3	8.2	7.8
GNP	431	592	813
Private consumption	216	248	286
Public consumption	118	144	176
Gross investments	85	108	137
Comm. & industry	71	94	124
Of this: industry	17	21	26
Publ. authorities	13.5	14.5	15.5

* The figures in the table were obtained from the values for 1977 and the growth rates in Table 3-5. The deflator for the change in monetary value from 1977 to 1978 was taken to be 1.08.

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4. ENERGY SCENARIOS

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4.1 Introduction

Three different scenarios were chosen for the hydrogen market study in order to illustrate how hydrogen can compete against various other kinds of energy. The three scenarios can very briefly be characterized as follows:

Scenario A:

HYDROGEN - NUCLEAR ENERGY

Hydrogen is produced by electrolysis or by thermochemical methods (high temperature reactors). Electricity is the main competitor to hydrogen.

Scenario B:

HYDROGEN - RENEWABLE ENERGY SOURCES

Hydrogen is produced by chemical, photochemical or biochemical conversion. Electrolysis is also conceivable. The most important competitiors to hydrogen are methane, methanol, ethanol and other fuels based on biomass.

Scenario C:

HYDROGEN - NATURAL GAS AND IMPORTED SYNTHETIC FUELS

In this scenario, the "traditional" oil import is successively replaced by imported gas and synthetic fuels produced from coal. The competitors to hydrogen are synthetic petrol and synthetic "natural" gas (SNG). It is assumed that a pipeline system for natural gas is being built during the period 1980 - 2000. The pipeline network is assumed to cover a number of "energy dense" regions in the country. Details concerning the gas systems are given in Section 4.4. As a consequence of a shortage of natural gas (NG) after the year 2000, increasing fractions of hydrogen may be introduced into the pipeline system. The hydrogen can be produced by a mixture of the techniques given in scenarios A and B.

More detailed descriptions of the three scenarios are given in Sections 4.2, 4.3 and 4.4. The energy demand given in Chapter 3 is used as the basis for the work. The energy balances given in the scenario descriptions in this chapter do not include the production and consumption of hydrogen. They describe instead the "background" energy market into which hydrogen may be introduced. The final energy balances with hydrogen included in the system are given in Chapter 16. When making the various scenarios some common assumptions were used, i.e:

- The fraction of electricity energy consumed by industry is steadily increasing. In 1975 24 % of the energy supplied to industry was electricity. The SIND study (cf Section 3.2) predicts that it will be 33 % in 1995. For the years 2005 and 2025 the corresponding figures were assumed to be 35 % and 39 %, respectively.

- The fraction of electricity in the transportation sector is also increasing (due to increased rail travel etc). The magnitude of the electricity demand of this sector is rather small, however, as long as electrical automobiles are not introduced on a large scale.

- For the other parts of the transportation sector (i.e. for non rail-bound vehicles) it is assumed that petrol and Diesel oil (produced from naphta) will still be used as fuels. During the period up to 2025, these fuels will be replaced by other fuels of various types in the three scenarios. In the year 2025, no naphta-based fuels are used.

- The technique for storing electricity for vehicle engines is assumed to have been developed to such a degree that batteries are available which allow a range of at least 300 km between loading and that such batteries can be obtained at reasonable costs.

- Within the transportation sector, it is assumed that about 30 % of the energy consumption will be for purposes other than domestic transport of people and goods. The main part of this consumption is for international air traffic, for international shipping and for the Swedish army, navy and air forces. The consumption consists mainly of jet fuels and heavy oils and is not replaced by other fuels.

- For all the scenarios the nuclear power stations are supposed to be of "traditional" type. No breeders or other advanced reactors have been introduced into the basic scenarios.

- The system of power stations of various kinds has only been designed to meet the yearly demand for electrical energy. No calculation of the peak power requirements has been done. Similarly, no calculation has been done for the distribution of production capacity over stations of various characters (base load, peak load stations etc). It has been assumed that after the year 2000 there will be improved possibilities for load-matching operation of nuclear power stations. The hydro-power installations are also assumed to be more easily regulated (larger power capacity). Finally, an increase in the capacity of pumping power stations is assumed to be available. Taken together these assumptions are considered to give sufficiently good dynamic properties for the electricity production system.

- The following efficiency values (taken from (1)) have been used for steam and hot water production based on various types of energy (fuels and electricity):

	Efficiency	Incl 10 % distribution losses of a district heating system
Electricity	1.0	
Oil	0.9	0.81
Coal	0.87	0.79
Gas*	0.9	0.81
Biomass	0.85	0.76
Peat	0.85	0.76
Uranium	0.80	0.72

* Including hydrogen.

- In the energy balances of the various scenarios, there seems to be a disagreement between the total energy supply to the different demand sectors and the consumption of energy in the same sectors. This is due to the fact that the energy demand is expressed in a "supply structure" which is similar to that of today. Large changes may occur when oil is replaced by other fuels (cf above). Particularly remarkable apparent discrepancies are obtained in the transportation sector if a large share of electrical automobiles is introduced. The demand for electricity for battery loading is only about 15 % of the corresponding petrol demand expressed in energy terms. Similarly, when biomass and peat replace fuel oil, the amount of energy supplied must be increased by 6 %.

4.2 Scenario A: Hydrogen - nuclear energy

Scenario A is basically a nuclear energy scenario. The oil import is replaced by nuclear power and by nuclear heating. In order to conserve electricity, heat pumps are used to a large extent in connection with space heating. This leads to a rather large need for peak electrical power during cold winter days.

In industry, the fuels of today are mainly replaced by electricity (for steam production etc). In 2025, there remain only some coal (mainly for metallurgical purposes) and the internal fuels in the pulp industry. There is, accordingly, only very limited possibility for producing electricity by back pressure turbines.

In the transportation sector, electrical automobiles are used to a large extent. The maximum fraction of electrical automobiles is assumed to be 25 %, 50 % and 75 % for the years 2005, 2015 and 2025, respectively. Furthermore, it has been assumed that the demand for electrical energy for battery loading is about 15 % of the corresponding fuel demand (expressed as petrol for Otto cycle engines) for the same transportation work. As a result of the limitation in the market introduction of electrical vehicles, as mentioned above, an inbalance will occur between supply and demand for engine fuels. Therefore some synthetic fuels (methanol, petrol etc) must be introduced in this scenario. Certainly this market could also be regarded as a potential market for hydrogen.

In the service and residential sector, electricity plays a dominant role. The demand for space heating is assumed to be covered by a mix of "conventional" electrical heating (direct or through a water system) and electrical heat pumps (which use water, ground or out-door air as the heat reservoir). District heating is introduced to a limited extent, since electricity is very well suited for distribution to individual houses. The district heating in scenario A is based on transport of "waste heat" from the nuclear power stations Forsmark, Ringhals and Barsebäck to the three closely populated regions around Stockholm, Göteborg and Malmö, respectively, and from 7 nuclear district heating units serving other large population areas. For these estimations, material from (1) was used. No other district heating centres will be used, and hence there will be no possibilities for combined electricity and heat production in such units.

The electricity production is dominated by nuclear power. Hydro power contributes with 256 PJ (71 TWh) and wind power with about 54 PJ (15 TWh), which corresponds to a little more than 1000 wind power units at 4 MW (about 100 m turbine diameter).

A description of scenario A is given in Tables 4-1, 4-2, 4-3 and 4-4.

Table 4-1

Energy demand, scenario A.

Assumed energy demand (PJ)	2005	2025
Industry, total	814	1001
Electricity	285	390
Fraction electricity excluding electricity for steam production	35 %	39 %
(The figures do not include fuel for production of electricity in back pressure turbines)		
Transportation, total expressed as the fuel energy content according to current structure of demand, see explanation in the text (page 4 - 5). (The figures include 36 PJ electricity for railbound traffic.)	335	389
Service and residential, total	608	666
Electricity for purposes other than space heating	234	256

Continued

Table 4-1 Continued

Distributed energy demand (PJ)	2005			2025		
	fuel	hot water	el.	fuel	hot water	el.
Industry						
Coal and coke	133			133		
In situ wood fuels	144			144		
Heavy fuel oil	141			0		
District heat		10			10	
Electricity for steam production			90			290
Other electricity			285			390
	418	10	375	277	10	680
Total		803			967	
Transportation						
Petrol	86			0		
Diesel	43			0		
Jet fuel	33			39		
Heavy fuel oil	67			78		
Synthetic fuels	40			66		
Electricity for batteries			8			24
Electricity for rail-bound trafic			36			36
	269	-	44	183	-	60
Total		313			243	
Services and residential						
Light fuel oil	100			0		
District heat		83			83	
Electrical heat			120			136
Electricity for heat pumps*			17			60
Other electricity			234			256
	100	83	371	0	83	452
Total		554			535	

* Assumed efficiency factor = 2.5.

Table 4-2

Production of hot water for district heating, scenario A.

DEMAND (PJ)	2005	2025
Final demand	93	93
Distribution losses	9	9
Total net production	102	102

SUPPLY (PJ) Nuclear heat production units Hot water centres Year	Uranium	Total hot water
2005	43	34
2025	43	34

SUPPLY (PJ) Nuclear power stations Combined production of hot water and electricity Year	Uranium	Total electricity	Total hot water
2005	155	58	68
2025	155	58	68

Table 4-3

Electricity balance, scenario A.

	2005	2025
DEMAND (PJ)		
Final demand	790	1193
Distribution losses	79	119
Total net production	869	1312
SUPPLY (PJ)		
1. Hydro	256	256
2. Nuclear (condensing)	493	916
3. Nuclear (back pressure)	58	58
4. Wind	44	64
5. Industrial back pressure	18	18
	869 (241 TWh)	1312 (364 TWh)
Fuel supply for item 3, see Table 4-2		
Fuel supply for item 2 (PJ)		
uranium	1494	2776
Fuel supply for item 5 (PJ)		
coal	8	8
heavy fuel oil	8	0
in situ wood fuels	6	14

Table 4-4

Total energy supply, scenario A.

	1978	2005	2025
FUELS (PJ)			
Uranium	257	1692	2974
Coal and coke	65	141	141
Light fuel oil & Diesel	1136	143	0
Heavy fuel oil		216	78
Petrol & jet fuel		119	39
In situ wood fuels	132	150	158
Synthetic motor fuels	0	40	66
	1590	2501	3456
DIRECT ELECTRICITY (based on renewable sources)			
Hydro	207	256	256
Wind	0	44	64
	207	300	320
TOTAL (PJ)	1797	2801	3776
(TWh)	499	778	1049

4.3 Scenario B: Hydrogen - renewable domestic energy sources

In this scenario, the fraction of electricity is considerably smaller than in scenario A. Electricity is mainly used within industry and with great restrictivity within the service and residential sector. Electrical heating is used on a very small scale. The supply of electricity is based on hydro power, but in this scenario the hydro contribution is again limited to 256 PJ/normal year. The wind power programme is almost twice as extensive as in scenario A. The remaining need for electricity is covered by production in power stations or in combined heat and power stations fuelled by wood or peat. The demand for electricity will probably have to be restricted by various regulations. A differentiated pricing system for electricity may be necessary to "protect" important industries and at the same time to keep down the demand from the service and residential sector.

In industry, coal, coke and in situ fuels are used to the same extent as in scenario A. The oil is replaced by biomass (mainly wood from energy plantations and forest residues) and peat. Some additional coal must be imported because of the minimum time required to achieve a sufficiently large domestic fuel supply.

In the transportation sector, various synthetic fuels (methanol, synthetic petrol etc) play an increasingly important role. These fuels are assumed to be produced within the country from domestic biomass and peat. In this case again, it may be necessary to use some imported coal as a raw material until adequate quantities of wood and peat are available. The methanol production from domestic raw materials is assumed to have an efficiency of 50 %. A further refinement of methanol to petrol gives an energy loss of about 16 %.

District heating techniques are used to a large extent in the service and residential sector. This facilitates the introduction of domestic solid fuels, which are preferably used in large facilities with possibilities for smoke-gas cleaning, rational handling systems for fuel and ash etc. Furthermore, about 40 PJ of solar heating is used in the district heating systems. Houses situated in areas not coupled to district heating systems are assumed to have individual wood burning fires, electrical heating (direct or through a heat pump) or heat pumps operated by methanol fuelled combustion engines.

In the system for electricity production, the nuclear contribution is kept at the "12 unit level". The wind power is expanded to 90 PJ (25 TWh) in 2025, which corresponds to about 2000 large wind power turbines. Thanks to the very extensive use of combustion in industry and for district heating, there is quite a large potential for the installation of back pressure turbines, which has also been used in this scenario. In the year 2025, this type of electricity production amounts to about 100 PJ/year.

Scenario B contains a massive programme for the utilization of peat and for the production of biomass, mainly in energy plantations. The production rate of biomass for energy purposes is assumed to increase even more rapidly than was assumed by the Energy Commission (2) but not as much as in the solar scenario of "Solar versus nuclear" (3). The supply of biomass in 2025 (about 1000 PJ) is assumed to be distributed between 850 PJ from energy forests and 150 PJ from forest residues and straw etc. The area needed for energy forests will be very roughly 3 million ha, which is about 7 % of Sweden's total land area.

A description of scenario B is given in Tables 4-5, 4-6, 4-7, 4-8 and 4-9.

Table 4-5

Energy demand, scenario B.

Assumed energy demand (PJ)	2005	2025
Industry, total	814	1001
Electricity	285	390
Fraction electricity	35 %	39 %
(The figures do not include fuel for production of electricity in back pressure turbines)		
Transportation, total expressed as the fuel energy content according to current structure of demand, see explanation in the text (page 4 - 5). (The figures include 36 PJ electricity for railbound traffic.)	335	389
Service and residential, total	608	666
Electricity for purposes other than space heating	234	256

Continued

Table 4-5 Continued

Distributed energy demand (PJ)	2005			2025		
	fuel	hot water	el.	fuel	hot water	el.
Industry						
Coal and coke	169			169		
In situ wood fuels	140			140		
Heavy fuel oil	40			0		
Biomass	137			250		
Peat	45			70		
District heat		16			16	
Electricity			285			390
	531	16	285	629	16	390
Total	832			1035		
Transportation						
Petrol	86			0		
Diesel	43			0		
Jet fuel	33			39		
Heavy fuel oil	67			78		
Synthetic fuels	70			236		
Electricity for rail-bound traffic			36			36
	299	-	36	353	-	36
Total	335			389		
Service and residential						
Light fuel oil	40			0		
Methanol for heat pumps*	10			37		
Heavy fuel oil	30			0		
Biomass	10			20		
District heat		216			216	
Electricity for heat pumps**			10			25
Other electricity			234			256
	90	216	244	57	216	281
Total	550			554		

* Assumed efficiency factor = 2.0

Table 4-6

Production of hot water for district heating, scenario B.

DEMAND (PJ)	2005	2025
Final demand	232	232
Distribution losses	23	23
Total net production	255	255

SUPPLY (PJ)
Hot water centres

Year	Peat	Biomass	Waste heat and garbage	Solar heat	Total hot water
2005	40	40	11	43	122
2025	40	40	11	43	122

SUPPLY (PJ)
Combined production of hot water and electricity

Year	Uranium	Peat	Biomass	Total electricity	Total hot water
2005	155	22	72	76*	133
2025	155	22	72	76*	133

* Including 58 PJ from combined nuclear stations.

Table 4-7

Production of methanol (PJ), scenario B.

Year	Coal	Peat	Biomass	Total methanol
2005	50	50	60	80
2025	60	80	406	273

Table 4-8

Electricity balance, scenario B.

	2005	2025
DEMAND (PJ)		
Final demand	565	707
Distribution losses	57	71
Total net production	622	778
SUPPLY (PJ)		
1. Hydro	256	256
2. Nuclear (condensing)	162	162
3. Nuclear (back pressure)	58	58
4. Wind	60	110
5. Industrial back pressure	40	80
6. Power heat stations (fuelled)	18	18
7. Other condensing	28	94
	662 (173 TWh)	778 (216 TWh)
Fuel supply for items 3 and 6, see Table 4-6		
Fuel supply for item 2 (PJ)		
uranium	491	491
Fuel supply for item 5 (PJ)		
peat	25	40
biomass	25	60
Fuel supply for item 7 (PJ)		
peat	30	97
biomass	45	150

Table 4-9

Total energy supply, scenario B.

	2005	2025
FUELS (PJ)		
Uranium	646	646
Coal and coke	219	229
Light fuel oil & Diesel	83	0
Heavy fuel oil	137	78
Petrol & jet fuels	119	39
In situ wood fuels	140	140
Peat	212	367
Biomass	389	998
	1945	2497
DIRECT ELECTRICITY (based on renewable sources)		
Hydro	256	256
Wind	60	110
	316	366
TOTAL (PJ)	2261	2863
(TWh)	628	795

The corresponding figures for the year 1978 are given in Table 4-4.

4.4 Scenario C: Hydrogen - natural gas and imported synthetic fuels

In this scenario, the import of oil and oil products is replaced by an import of natural gas and synthetic fuels (gaseous or liquid). The imported synthetic fuels may for instance be produced from coal. According to the assumptions in this study, the import of coal is to be restricted. Another important assumption is that a large-scale distribution network for natural gas is built to serve the main population and industrial centres of Sweden during the period before 2000. After the year 2000 the supply of natural gas is assumed to be diminishing. Progressively increasing quantities of SNG or possibly hydrogen must therefore be fed into the pipeline network.

In this scenario as in scenario B, the nuclear power contribution is limited to about 12 reactors, in order to get a pronounced profile for the scenario. Electrical heating may therefore only be used to a very small extent. Fuels to be burned for space heating are gas or other imported refined fuels. From an economical point of view, it would probably be more favourable to use coal for the production of steam and hot water in industry and for district heating, but according to the assumptions for the study, this is not allowed. It is assumed that the natural gas network is introduced according to the proposals given in the reports from Swedegas to the Department of Industry (4, 5), that is:

Stage 1	Project "South gas" -	consumption	1.2 G(m^3)/year
Stage 2	Project "West gas" -	consumption	1.8 G(m^3)/year
Stage 3	Project "East gas" -	consumption	2-3 G(m^3)/year
		Total	5-6 G(m^3)/year

The installations according to these three projects are assumed to be finished before 1990. A detailed description of the pipeline system is given in (4) together with a description of the demand structure.

It is assumed in this study that later on the pipeline system will be expanded to meet a yearly demand of about 7 G(m^3). Even in this case, only large energy consumers are assumed to be connected to the gas system. The natural gas is, accordingly, mainly used to replace heavy fuel oil in industry and for district heating (4). By this time gas has overtaken the greater part of the potential market for combined nuclear power/heating stations and also for pure nuclear heating units. The "waste heat" from some nuclear power plants, which in scenarios A and B was used for district heating, will therefore not be utilized in scenario C. Some electricity generation takes place in gas-fuelled combined power/heating stations. No gas-fuelled condensing power stations are proposed (4). Similarly, there is no large-scale space heating based on gas outside the district heating systems and industry.

In the industrial sector, coal, coke and in situ wood fuels are used as in the other scenarios. Natural gas (or SNG) is an important fuel. Most of the natural gas is used by industry. The remaining demand for fuel is covered by synthetic oil products.

In the transportation sector, the problems of adaptation will be very small in this scenario because the traditional types of fuel will still be available. The only difference is that these fuels are synthetic instead of naphta based. Imported methanol may also turn out to be a competitor to synthetic petrol.

In the service and residential sector, there is a rather high fraction of district heating. As was mentioned earlier, the district heat is produced mainly by gas or oil fuelled stations. A considerable fraction of oil burning is used in individual houses or in smaller systems covering all houses in one block or so. Synthetic Diesel oil is used for operation of heat pumps.

A description of scenario C is given in Tables 4-10, 4-11, 4-12 and 4-13.

Table 4-10

Energy demand, scenario C.

	2005	2025
Industry, total	814	1001
Electricity	285	390
Fraction electricity	35 %	39 %
(The figures do not include fuel for production of electricity in back pressure turbines)		
Transportation, total expressed as the fuel energy content according to current structure of demand, see explanation in the text (page 4 - 5). (The figures include 36 PJ electricity for rail-bound traffic.)	335	389
Service and residential, total	608	666
Electricity for purposes other than space heating	234	256

Continued

Table 4-10 Continued

Distributed energy demand (PJ)	2005			2025		
	fuel	hot water	el.	fuel	hot water	el.
Industry						
Coal and coke	130			130		
In situ wood fuels	155			155		
Heavy fuel oil	116			144		
Natural gas and SNG	108			162		
District heat		18			18	
Electricity			285			390
	509	18	285	591	18	390
Total		812			999	
Transportation						
Petrol	86			0		
Diesel	43			0		
Jet fuel	33			39		
Heavy fuel oil	67			78		
Synthetic fuels	70			236		
Electricity for rail-bound traffic			36			36
	299	-	36	353	-	36
Total		335			389	
Service and residential						
Light fuel oil	31			16		
Diesel for heat pumps*	30			70		
Heavy fuel oil	70			32		
District heat		166			166	
Electrical heat			20			20
Other electricity			234			256
	131	166	254	118	166	276
Total		551			560	

* **Assumed efficiency factor = 2.0.**

Table 4-11

Production of hot water for district heating, scenario C.

DEMAND (PJ)	2005	2025
Final demand	184	184
Distribution losses	18	18
Total net production	202	202

SUPPLY (PJ)
Hot water centres

Year	Heavy fuel oil	Gas	Total hot water
2005	70	10	72
2025	65	15	72

SUPPLY (PJ)
Combined production of hot water and electricity
Power/heat stations

Year	Heavy fuel oil	Gas	Total electricity	Total hot water
2005	212	44	65	130
2025	200	60	65	130

Table 4-12

Electricity balance, scenario C.

	2005	2025
DEMAND (PJ)		
Final demand	575	702
Distribution losses	58	70
Total net production	633	772
SUPPLY (PJ)		
1. Hydro	256	256
2. Nuclear (condensing)	225	225
3. Wind	40	64
4. Industrial back pressure	45	65
5. Power/heat stations (fuelled)	65	65
6. Other condensing	2	97
	633 (176 TWh)	772 (214 TWh)
Fuel supply for items 3 and 5, see Table 4-10		
Fuel supply for item 2 (PJ)		
uranium	682	682
Fuel supply for item 4 (PJ)		
heavy fuel oil	56	81
Fuel supply for item 6 (PJ)		
heavy fuel oil	5	243

Table 4-13

Total energy supply, scenario C.

	2005	2025
FUELS (PJ)		
Uranium	682	682
Coal and coke	130	130
Light fuel oil & Diesel*	104	86
Heavy fuel oil*	596	699
Petrol & jet fuel	119	39
Natural gas & SNG	162	237
In situ wood fuels	155	155
Synthetic fuels**	70	236
	2018	2264
DIRECT ELECTRICITY (based on renewable sources)		
Hydro	256	256
Wind	40	64
	296	320
TOTAL (PJ)	2314	2584
(TWh)	643	718

* Naphta based or synthetic.

** For the transportation sector.

The corresponding figures for the year 1978 are given in Table 4-4.

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5.0 Introduction

Hydrogen has been known to man for about two centuries. It was initially used as a buoyant gas, then as a component of synthetic fuel. At present, hydrogen is used almost entirely as a unique industrial chemical in petroleum processing and in the synthesis of ammonia and methanol. New uses are expected to arise, such as in the gasification and liquefaction of coal and as a direct special-purpose fuel.

Hydrogen is today mainly produced from natural gas (NG), petroleum products and coal as feedstocks. Only a small percentage is obtained from the direct splitting of water by electrolysis. Most of the hydrogen is consumed on site as a captive gas for the production of petroleum and chemical products. Only a small fraction (in the US c. 7 %) is sold as merchant gas in the open market. Tables 5-1 and 5-2 give a survey of production and consumption figures for the world, the US, the Common Market (EEC) and Sweden. Minor applications ("others" in Table 5-2) are for example in foodstuffs, soap, metal refining and annealing, semiconductor manufacture, rocket fuel, special chemicals and direct combustion.

Table 5-1

Hydrogen production and feedstocks (1975).

	Mton/ year	Percentage produced from feedstock			
		NG	Petroleum	Coal	Electrolysis
World	25				2
US	8	76	23		
EEC	4	60	31	9	
Sweden	0.4				

Table 5-2

Hydrogen consumption (1975) in percentages.

	NH_3	Petroleum refinement	Methanol	Plastics	Textiles	Others
World	50	25	8		4	13
US	36	47	10			7
EEC	55	23	9	8	4	1
Sweden	6.5	2.5				91*

* Mainly direct combustion (0.37 Mton/year).

The demand for hydrogen in the US has almost doubled during the last decade. The present increase is c. 8 % per year and is expected to follow this trend during the next 20 years, which means an annual demand of about 45 Mton by the year 2000 (1). To meet this demand, it is necessary to earmark a large fraction of the fossil fuel resources solely for hydrogen production, either 25 % of the coal available each year or 40 % of the NG.

According to a Delphi study (2), performed in 1974 - 1975 by the Belgian company SCIENCE with the aid of 86 experts from 13 countries, the world demand for hydrogen can be expected to rise to 155 - 265 Mtons/year in the year 2000. About 10 % of the available world's primary energy would be needed for the production of hydrogen, and hydrogen would account for about 5 % of the global energy consumption. The experts also anticipated that 30 % of the hydrogen would be produced by electrolysis, 10 % in closed thermochemical cycles and the rest by conventional methods.

The largest production plants for hydrogen have present-day capacities of 0.1 Mton/year (captive hydrogen from NG), while capacities for electrolysis plants are less than 0.04 Mton/year (for liquid hydrogen $\leq$ 0.02 Mton/year).

The total Swedish demand for energy has been almost constant over the last three years and amounts to c. 1620 PJ (450 Twh) which is equivalent to the energy content of 11.4 Mtons of hydrogen. Electricity consumption amounts to ca 325 PJ (90 TWh) $\cong$ 2.27 Mtons H_2.

If it is assumed that the market penetration in Sweden for hydrogen at the beginning of the next century is of the same order of magnitude as that projected for the world at large, and taking into account domestic production by electrolysis, an optimal and probable size of a future plant would be one directly connected to a power station (e.g. nuclear) with an electric output of 1000 MW. With an electrolysis efficiency of 0.8 and with the same average plant load, the production capacity would amount to 0.14 Mton hydrogen per year. This quantity will be used as a reference figure in economic considerations of different production methods.

5.1 Properties of hydrogen

Hydrogen is far more abundant in the universe than any other element. The estimated percentage is about 90. By contrast, hydrogen is not quantitatively a major element in the earth's crust. Its abundance here is estimated to be 1.4 kg/ton or about 1 % per weight. Expressed as an atomic percentage, hydrogen is second only to oxygen with an abundance of about 16 %. The major portion of the earth's hydrogen is combined with oxygen in water. It also occurs frequently combined with carbon, sulphur, nitrogen and chlorine and less frequently with the other halogens and phosphorus. Hydrogen is a constituent of all animal and vegetable tissue and also of most organic materials. Only a trace of hydrogen is found in the earth's atmosphere, but larger quantities are sometimes found in volcanic and other natural gases.

There are three isotopes of hydrogen, all of which occur naturally, but in very different amounts. The normal isotopic ratio of protium to deuterium (H:D) is 6409:1. The third isotope, the radioactive tritium (T), is formed by the action of high-energy cosmic radiation on nitrogen and is very scarce in nature. The total amount of naturally formed tritium has been estimated to be of the order of a few kilograms.

Molecular hydrogen, H_2, generally exists in two forms, namely ortho and para, with aligned electron spins in the former and opposed spins in the latter form. The equilibrium between them is a function of the temperature. The para percentage is 99.28 at 20 K and 25.13 at 273 K. Interconversion between them is not thermally activated to any appreciable extent until temperatures are reached that are high enough to cause dissociation and recombination (H-H bond rupture and recombination). If hydrogen is prepared at any given temperature, the equilibrium ortho-para ratio characteristic of that temperature persists at other temperatures unless the interconversion is catalyzed, for example by charcoal. The energy released by converting ortho-H_2 to para-H_2 is 704 J/g at 20 K, which is more than enough to revapourize liquid hydrogen (LH_2). It is therefore important during the liquefaction of gaseous H_2 (GH_2) to LH_2 to completely transfer the hydrogen to the para form.

Hydrogen can exist in the three normal forms of aggregation, gaseous, liquid and solid. The melting point is 13.96 K, the boiling point at 0.1 MPa 20.39 K and the critical temperature 33.3 K. Accordingly at normal temperatures, free hydrogen can only exist as the diatomic gas, which is odourless, tasteless and colourless. The most important physical properties of hydrogen are collected in Table 5-3. The data given here serve as a basis for this review.

The relatively high heat of dissocation for $H_2 \rightarrow 2H$ is responsible for the chemical inactivity of the gas. Very reactive atomic hydrogen can, however, be produced by the photodissocation of water vapour ($H_2O \rightarrow H + OH$). The required energy is 230 MJ/kg or a radiation wavelength < 260 nm. Only light of shorter wavelength than 185 nm is appreciably absorbed by water. At the same time, sunlight with a wave length shorter than 310 nm is absorbed by the earth's atmosphere. Water can therefore not be dissociated by sunlight in a simple single-photon process. For a many-photon process, the limit is set by the reaction $H_2O \rightarrow H_2 + \frac{1}{2} O_2$ with a required energy of 119 MJ/kg (507 nm).

Table 5-3

Physical data for hydrogen.

Molecular weight	2.016 g/mole
Heat of fusion at 14.0 K	58.66 kJ/kg
Heat of vapourization at 20.4 K	448.3 kJ/kg
Density LH_2 at 20.4 K	0.070 kg/l
Density GH_2 at 273 K	$9.00 \cdot 10^{-5}$ kg/l
Coefficient of thermal expansion per °C	0.00356
Heat of combustion	142.5 MJ/kg
Heat of combustion at 273 K (HHV); 0.1 MPa	12.77 MJ/m^3
Heat of combustion at 273 K (LHV)	10.72 MJ/m^3
Flame temperature in air	2400 K
Flame temperature in oxygen	3000 K
Flame velocity (air)	2.75 m/sec
Inflammability limits (air)	4 - 75 %
Inflammability limits (oxygen)	4 - 94 %
Detonability limits (air)	18 - 59 %
Ignition temperature	850 K
Ignition energy	20 μJ

Hydrogen is the lightest of all the elements, with a density of GH_2 that is only 7 % of that of air. The thermal conductivity is 6.7 times greater than that of air. The solubility in water is low, being 2.15 volume percentage at standard temperature and pressure (STP).

Hydrogen combines directly with most of the lighter elements to form hydrides, in the case of the more electronegative elements with the evolution of large amounts of energy. The only product formed during combustion in oxygen is water, which can be regarded as an oxygen hydride. If the temperature is limited to ca 1500 K during combustion in air, the formation of environmentally undesired NO_x compounds is avoided. A small spark is sufficient to start the combustion of hydrogen, which proceeds at a high temperature and with a very high speed and can lead to detonation. Due to the high diffusibility of hydrogen (c. 3 times faster than that for air or light hydrocarbons), the implications for the surroundings are seldom very serious. Environmental and safety aspects will be discussed more fully in Chapters 14 and 15.

Hydrogen is unreactive towards most metals at room temperature. Appreciable amounts of the gas can, however, be adsorbed by some metals, such as iron, gold, platinum and especially palladium. A single volume of palladium black at STP adsorbs about 870 volumes. Finely divided platinum, gold and iron adsorb volumes that are 20 - 40 times less. At elevated temperatures, hydrogen passes through the walls of containers made of these and some other metals.

The embrittlement of iron, steel and stainless steel produced by the occlusion of hydrogen and/or hydride formation is a problem of great significance in all large-scale uses of hydrogen. It can cause flaking, shatter-cracks, loss of forgeability, reduced shock resistance and tensile strength, lamellar fracture and blisters, as will be discussed further in Chapter 13.

Hydrogen in large bulk quantities is transported and distributed over long distances in the form of compressed gas, in conventional pipeline systems or in stainless steel tubes, and as a liquid, in well insulated and refrigerated Dewar vessels. The transport capacity of pipelines is very high and about the same as that for natural gas. Energy storage is a vitally important key in the utilization of intermittent energy supplies such as solar, wind, tidal and excess power in the operation of utility power stations. Very large quantities of GH_2 can be stored in compressed form in natural underground formations such as depleted gas fields or aquifers. LH_2 is cryogenically stored in large tanks (up to 5000 m^3) with premium insulation. Evaporation losses have to be taken into consideration. The most compact storage method is provided by solid forms such as the fairly expensive hydrides of light elements or their alloys, for example Mg, Fe, Ti and the rare earths. Aspects of storage and transmission are described in greater detail in the Chapters 6 and 7.

5.2 Primary energy sources

Hydrogen exists as a free element only in minor amounts in nature. The large amounts of the energy carrier required in a possible future hydrogen society can only be produced from raw materials which contain a high fraction of hydrogen and are available at a low price in almost unlimited amounts. Water is the only feedstock that fulfils these requirements. Secondary possibilities are oil, NG and biomass.

The energy necessary to split water or hydrocarbonaceous material must be supplied by a primary energy source. All existing primary energy sources on earth can be used for this purpose, i.e. direct solar, wind, geothermal, ocean thermal and salt gradients, waterfall, biomass, nuclear and fossile fuel. Figure 5-1 sketches the connections between primary energy sources, energy conversion systems, raw materials and hydrogen production methods. The competitive strength of the different production routes is mainly a function of the efficiency of the total energy conversion system, of the raw material cost and of the capital cost for the complete system. Environmental and safety aspects must also be taken into consideration but are usually difficult to quantify.

The primary energy sources mentioned above can also all be used for the manufacture of the most important future alternatives to hydrogen as an energy carrier. These are primarily synthetic hydrocarbon gas and petrol, methanol and electricity. Apart from electricity, a carbonaceous raw material and usually also water are needed for their production. Hydrogen can be used as an alternative to water for the production of these materials and also for the direct generation of electricity.

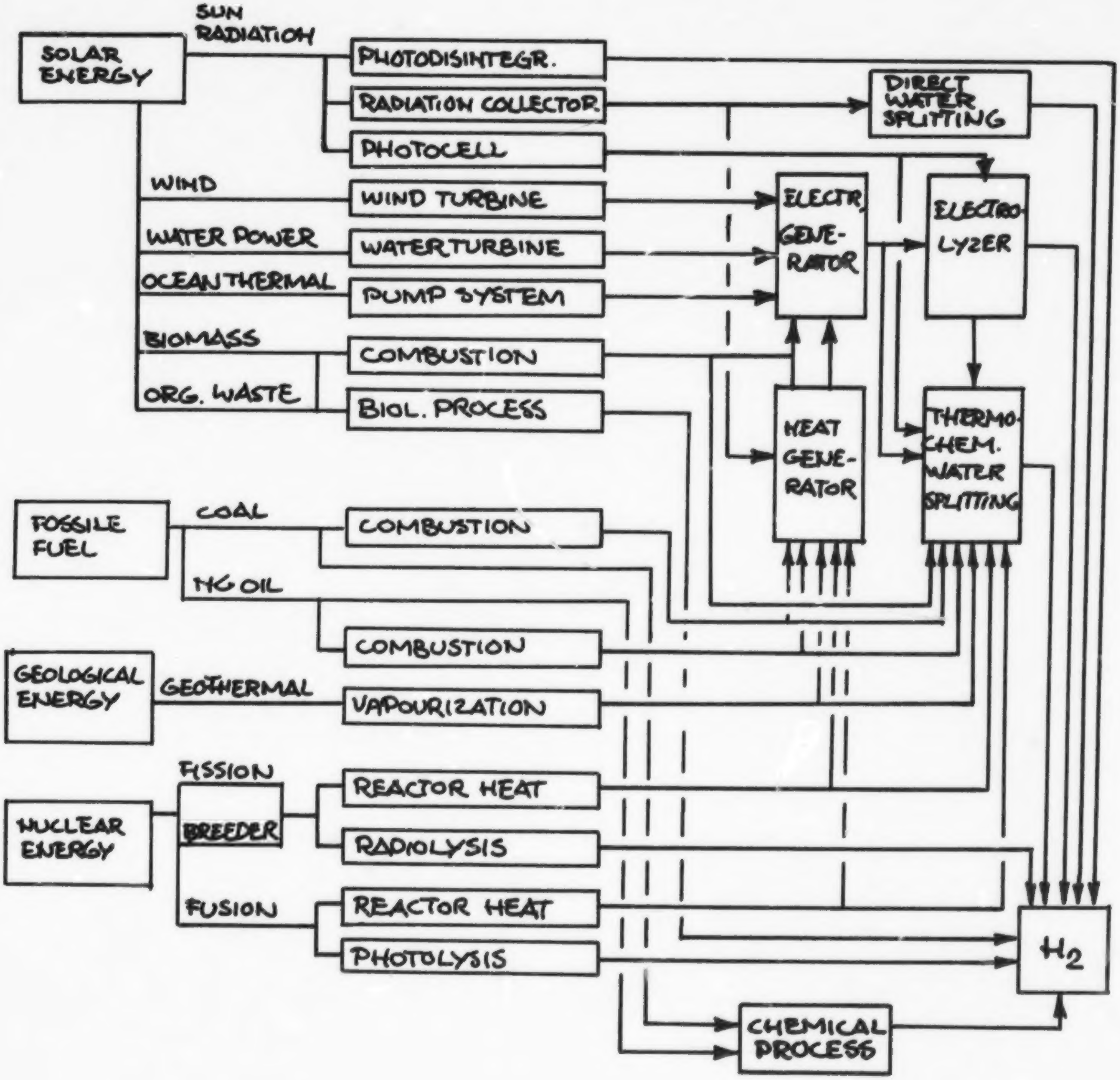
SOLAR ENERGY
SUN RADIATION
PHOTODISINTEGR.
RADIATION COLLECTOR
PHOTOCELL
DIRECT WATER SPLITTING
WIND
WIND TURBINE
WATER POWER
WATERTURBINE
OCEAN THERMAL
PUMP SYSTEM
BIOMASS
COMBUSTION
ORG. WASTE
BIOL. PROCESS
ELECTR. GENERATOR
ELECTROLYZER
HEAT GENERATOR
THERMO-CHEM. WATER SPLITTING
FOSSILE FUEL
COAL
COMBUSTION
NG OIL
COMBUSTION
GEOLOGICAL ENERGY
GEOTHERMAL
VAPOURIZATION
NUCLEAR ENERGY
FISSION
BREEDER
FUSION
REACTOR HEAT
RADIOLYSIS
REACTOR HEAT
PHOTOLYSIS
H_2
CHEMICAL PROCESS

Figure 5-1

Hydrogen production methods from primary energy sources.

5.3 Production methods

As is apparent from Table 5-1, gaseous and liquid hydrocarbons are today the dominating feedstocks for the production of hydrogen. Outside the US, carbon is rapidly growing in importance. The splitting of water by electrolysis is only of minor significance and is related mainly to the production of high-purity (> 99.5 %) hydrogen. The other methods sketched in Figure 5-1 are only in their research and development stage and have a long way to go before they can be adapted for use in large-scale plants.

Due to the expected decrease in the supply of fossil hydrocarbons and, according to the project assumptions, to the elimination of carbon as a domestic energy source of major significance, emphasis will be placed on hydrogen production methods which use water as the main feedstock. Oxygen is always obtained as a by-product during the dissocation of water and can be used, with air as an alternative, in the conversion of the hydrogen to more suitable energy forms. The only product of combustion obtained is water. The complete cycle is demonstrated in Figure 5-2.

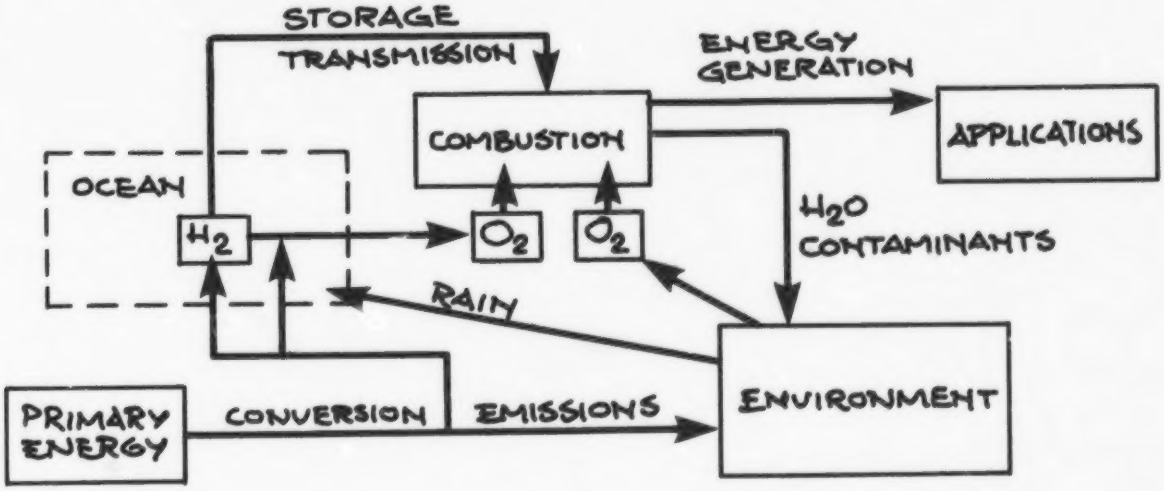

Figure 5-2

The hydrogen cycle.

Unless otherwise explicitly stated, the following pre-requisites are used as a basis for all economic calculations. The conditions given in Chapter 1 are adopted. All cost figures are quoted in terms of the average 1978 value of the Swedish crown (cr). Other currencies are transformed with the aid of Table 2-2. A real interest rate of 4 % is applied, and the depreciation is set to 10 years, i.e. an annuity of 12.33 %. The common fuel price scenario of the IEA Study Group, Table 2-1, is adapted for conventional fuels (coal, oil products, NG, methanol).

5.3.1 Direct thermal splitting of water

At sufficiently high temperatures water will undergo appreciable dissociation into its elements, hydrogen and oxygen. The reaction proceeds in one step with an enthalpy requirement of 119.6 GJ/ton (15°C, 0.1 MPa):

$$H_2O(g) \rightarrow H_2(g) + \tfrac{1}{2} O_2(g)$$

The point of equilibrium depends primarily upon the temperature but is also inversely proportional to the pressure, as is apparent from the reaction formula.

Table 5-4 presents some data for the dissocation of water vapour as a function of the reaction temperature at a total pressure of 0.1 MPa (3, 4). The percentage of hydrogen formed is calculated from the equilibrium constant K_p (for pressure) with mole fractions substituted for the partial pressures of the reactants. The conventional thermodynamic relation applies for K_p:

$$\Delta G = -RT \ln K_p$$

where

ΔG = the free energy change

The theoretical efficiency is the ratio between the HHV of hydrogen and the sum of all heat and work functions required to accomplish the reaction, including the extra work needed to separate the products. Lack of reversibility coupled with heat losses would seem to result in practical efficiencies of about 50 - 65 % of those listed for temperatures $T > 2000$ K, while they are very low for $T \ll 2000$ K. By lowering the pressure, the yield of hydrogen (expressed as a percentage of the original water reactant) can be increased.

Table 5-4 shows that a high yield of hydrogen can only be obtained at $T > 3000$ K. Suitable primary energy sources capable of achieving such high temperatures are, for example, solar energy concentrated by mirror fields or fusion reactors. Efficient methods must also be developed to rapidly separate the hydrogen and oxygen thus formed. Palladium membranes which are transparent to hydrogen could accomplish this. A diagrammatic scheme for the complete process is shown in Figure 5-3.

Table 5-4

Thermodynamic data and efficiency for thermal splitting of water.

Temperature K	Enthalpy change MJ/kg	Free energy change MJ/kg	K_p	Hydrogen yield mole %	Theoretical efficiency %
500	122.1	112.1	$1.3\cdot10^{-23}$	$7\cdot10^{-14}$	43
1000	124.1	96.5	$8.7\cdot10^{-11}$	$2.5\cdot10^{-5}$	47
1500	125.3	82.3	$1.9\cdot10^{-6}$	$1.9\cdot10^{-2}$	50
2000	126.0	67.9	$2.9\cdot10^{-4}$	0.55	52
2500	126.5	53.3	$5.05\cdot10^{-3}$	3.8	55
3000	126.8	38.65	$4.55\cdot10^{-2}$	15	57
3500	127.2	23.90	0.194	34	59
4000	127.6	9.11	0.578	56	61
4500	128.1	-5.72	1.36	72	63

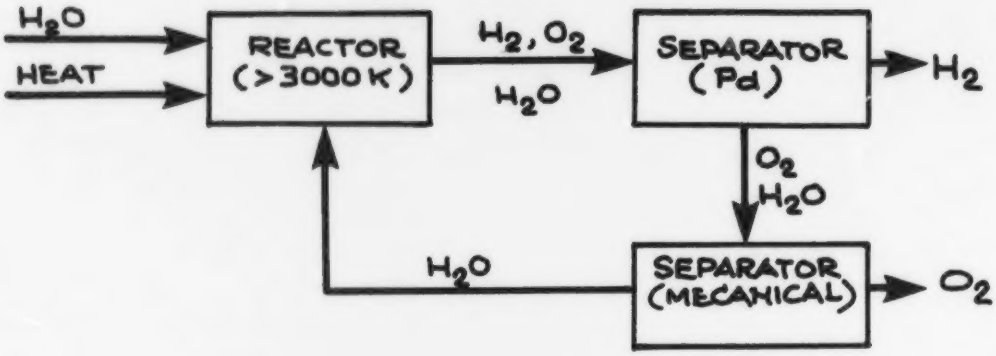

Figure 5-3

Thermal water splitting cycle.

Estimates of the price of hydrogen produced by mirror concentrated solar energy at 3000 K have been made in a recent Japanese publication (5). Using these figures and adjusting them to conditions valid for this investigation (5.3), the results (valid for 1978) given in Table 5-5 were obtained. It is assumed that thermal solar energy can be produced at a cost of 0.03 cr/kWh and used in the plant at a total efficiency of 30 %. Hydrogen is obtained at a pressure of 0.1 MPa and compressed to 10 MPa (electricity cost 0.088 cr/kWh). The average effective plant operation time is 2000 h per year.

Table 5-5

Cost figures for a large solar heated hydrogen plant.

Capital investment	1000	cr/kW H_2
Capital costs	17.1	cr/GJ H_2
Heat costs (solar energy)	27.8	"-
Running costs: electricity	4.2	"-
other	4.4	"-
Total costs	53.5	cr/GJ H_2

It must be stressed that the cost figures are highly hypothetical. Investments for a large plant with an annual capacity of 0.14 Mton H_2 will be about 2.75 Gcr for the year 1978, excluding the investment for the solar heat plant which is of the order of 1 Gcr.

5.3.2 Electrolysis of water

Water electrolysis is a commercially available technology but is today of minor importance for the production of hydrogen. There are few large plants, and they rely upon cheap water power. Units with annual capacities of 0.04 Mton exist, for example Aswan in Egypt, Nangal in India and Rjukan in Norway. However, the production is usually restricted to small plants, where the high purity of the product gas and the flexibility of the process are considered as prime qualities.

The electrolysis process is very simple in principle. The basic cell consists of a pair of electrodes immersed in a conducting water solution. A direct current is passed through the cell resulting in the evolution of hydrogen and oxygen at separate electrodes, and water is continuously consumed. The basic cell has no moving parts and is reliable and trouble-free. In addition, electrolysis is the most efficient way of generating hydrogen under the pressure required for distribution of the gas in pipelines. An increase in the cell operating pressure results in a higher voltage requirement, but normally more efficient work is obtained, which more than offsets the extra electrical energy required.

Compared with other hydrogen production methods, the most important characteristic of electrolysis is the direct separation of hydrogen and oxygen in highly pure forms in the cell. The principal disadvantage is that an expensive high-energy form, namely electric power, is used as input to the cell. The generation of electricity is the energy inefficient step of the process, while the electrolytic generation of hydrogen must be regarded as completely acceptable from an energy point of view with efficiencies above 75 %. More than 80 % of the production price for hydrogen is due to the cost of electricity.

A basic electrolyzer cell consists of the following parts: an electrolyte, two electrodes, a separator and a container which serves to hold the electrolyte. The electrolyte must exhibit a high ionic conductivity, be chemically inert to decomposition at the applied voltage and non-volatile, and buffer the solution at a constant pH. These criteria are met by strong acids (H_2SO_4) and alkalis (KOH). The electrodes must have a suitable catalytic surface for the nucleation and detachment of hydrogen and oxygen gas bubbles and provide a large area interface to the electrolyte. In alkaline cells, nickel or nickel-plated steel is most commonly used. Other alternatives are precious metals like gold, platinum and iridium. The purpose of the separator is to prevent short-circuiting and to separate the evolved gases while affording an ionic conducting path with a low resistance between the two half-cells. It must be non-corrosive and structurally stable during the operating life of the cell. The separator is therefore usually made in the form of a thin sheet of a porous diaphragm or a matrix. Asbestos is the material commonly used in alkaline cells.

The overall process of water decomposition by electrolysis is the reverse of hydrogen combustion:

$$2H_2O \rightarrow 2H^+ + 2OH^- \rightarrow H_2 + \tfrac{1}{2}\, O_2 + H_2O$$

Therefore, the theoretical amount of energy per unit quantity of hydrogen is the same as the HHV heat of combustion (ΔH), which according to Table 5-3 is 142.5 kJ/g.

The thermodynamic relationship which governs the reaction at constant pressure is

$$\Delta H = \Delta G + T\Delta S = -nFE + nFT\,\frac{\partial E}{\partial T}$$

$$\Delta G = -nFE$$

where

ΔH, ΔG,
and ΔS = the changes in enthalpy, free energy and entropy

E = the decomposition voltage

F = the Faraday value

$\frac{\partial E}{\partial T}$ = the temperature coefficient of E

The only energy that can be interchanged with electrical energy at constant temperature and pressure is the free energy. Entropy changes cannot be converted to electricity but must be supplied or liberated as heat. According to Table 5-1, the voltage corresponding to the free energy exchange (the reversible voltage) at 0°C and 0.1 MPa is 1.24 volts and that corresponding to ΔH is 1.475 volts. In an ideal case, the latter voltage would generate hydrogen and oxygen isothermally without any waste heat being produced. In the range down to 1.24 volts, the cell would still generate the gases while absorbing heat from the surroundings.

The enthalpy ΔH increases very slowly with temperature. On the other hand, ΔG decreases rather rapidly with a temperature increase, as is illustrated for the ideal case in Figure 5-4. These factors operate in favour of high temperature electrolysis, since the applied voltage can be lowered. At very high temperatures, with water fed into the cell as steam, the advantage is less pronounced, as the temperature slope of ΔG for H_2O in vapour form is less steep.

The pressure dependence of the decomposition voltage is only small. For every tenfold increase in pressure, the required voltage increases by 43 mV. This added energy will result in an equal increase in potential energy of the gas products. In practice, higher pressures give lower efficiency losses and cell operation close to ideal conditions, among other things due to the fact that the gas bubbles involved are smaller and provide less hindrance to the passage of the cell current. Thus the saving in energy is greater than the extra energy added.

In practice, extra energy requirements must be met for various parasitic reactions and non-ideal conditions. Pumps are required to circulate solutions, conversion of input power to DC voltage is necessary, and fairly large efficiency losses occur within the cell because of polarization effects of the electrodes which create a need for an overvoltage. Losses also occur due to the internal ohmic resistance in the cell, and they increase with increasing current. An optimum has to be found between the power requirements which increase with increasing cell currents and the capital costs which decrease with increasing production rates.

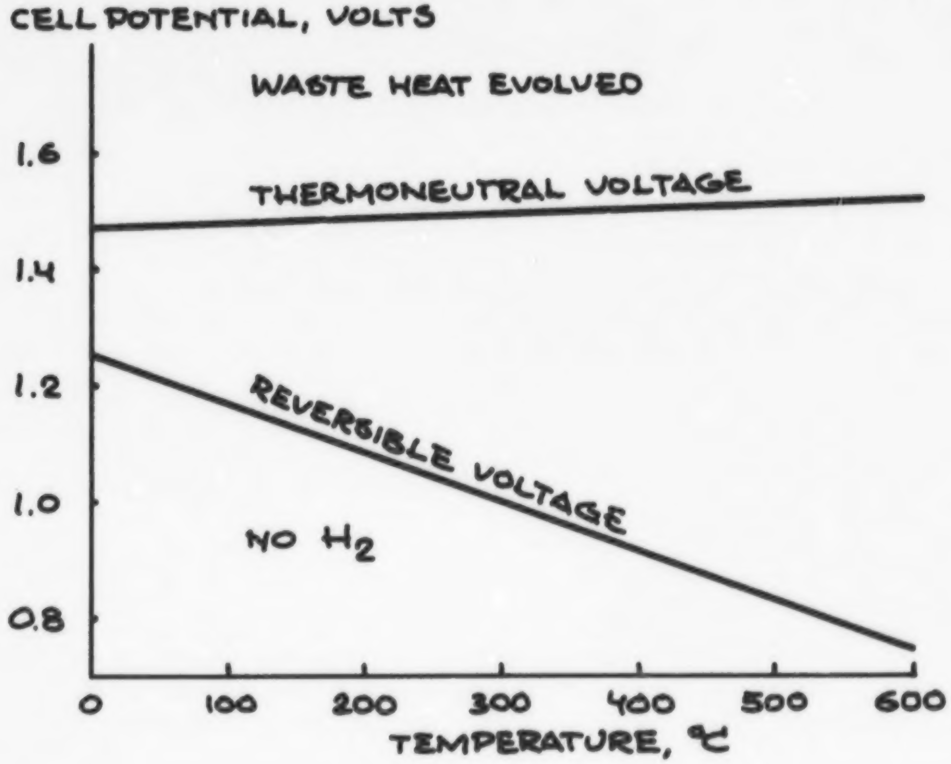

Figure 5-4

Ideal operating voltage at 0.1 Mpa.

5.3.2.1 Alkaline electrolysis

Alkaline electrolysis is today the only commercially applied electrolytic technique for the large scale production of hydrogen. The cells are run at atmospheric pressure and at a temperature of 60 - 70°C. The cathode electrode is usually made of mild steel and the anode, which is subject to greater corrosion, is as a rule made of nickel coated steel. The electrolyte is a 25 - 30 % KOH solution. The cell compartment is separated by a diaphragm made of a woven asbestos, which has satisfactory mechanical and corrosion resistant properties in the temperature range mentioned. Thin perforated nickel screens are sometimes chosen at higher temperatures. Current densities vary between 500 and 2000 amp/m^2, cell potentials between 1.8 - 2.2 volts, and the specific energy requirement is about 18 MJ/Nm^3 H_2. The total efficiencies of plants run today are 65 - 75 %. Hydrogen and oxygen purity is > 99.5 %.

The cell system is built up of the required number of multiple modules, either of bipolar or unipolar design. The former is usually of a filler-press type and has the individual cells in series electrically. A system might contain several hundred cells, each at about 2 volts, so that the corresponding applied voltage can amount to 1000 volts. A unipolar system is usually of the tank type and is connected in parallel electrically with an applied overall voltage requirement of about 2 volts. The two systems have different advantages and disadvantages but are economically about equally favourable and therefore applied to about the some extent.

Figure 5-5 illustrates a block diagram for a conventional process.

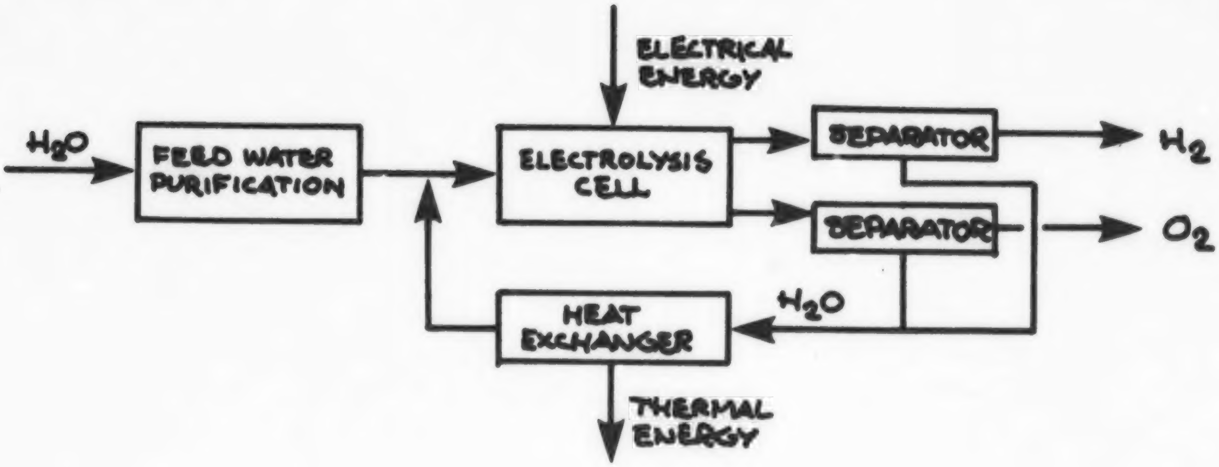

Figure 5-5

Block diagram of an electrolysis plant.

The development trend for alkaline electrolysis is directed towards the use of higher pressures, temperatures and current densities. A working pressure of up to 5 MPa enables the temperature to be increased to about 120 °C, gives more idealized performance in the cell and results in product gases which are more suitable for storage and transmission. In this way the compression work is completely recovered. Higher working temperatures result in a drop in the overvoltage and ohmic resistance. The gain in applied voltage has been estimated to be 5 mV/°C. Computations show that current densities of up to 10 kA/m^2 might give a favourable trade-off between capital and energy costs. New substitutes for asbestos as the separator material must be developed for operation temperatures above 120 °C. Advanced alkaline electrolyzer concepts are expected to be ready for large-scale application around 1985 with total efficiencies of up to 90 %.

An analysis has been made of about 20 published evaluations of cost data for large conventional and advanced alkaline electrolysis plants. Where it has been possible to fully interpret the data and specify the sub-headings, the figures are summarized in Table 5-6 with prices expressed in the US $-value of the year used for the investigation. To make the table more comparable, figures have been adjusted to a common basis, i.e. an annuity of 15 %, a plant load factor of 90 % and a power accomodation efficiency of 97 %.

As is apparent from the table, the calculated costs of the hydrogen product agree surprisingly well taking into consideration the different dollar values used. Electricity is the dominating cost element and varies between 56 - 74 %. If cheaper electricity is available, for example as off-peak or spinning reserve power, the hydrogen price can be substantially lowered.

Table 5-6

Operating costs in commercial alkaline electrolysis plants (US $).

	Ref 6	Ref 7	Ref 8	Ref 9	Ref 10	Ref 11	IEA**	IEA**	Ref 10*
Capital invest. $/kW_{el}$	270	355	560	555	335	250	380	260	340
Plant capacity Nm^3H_2/day	$2.4\cdot10^6$	$2.8\cdot10^5$	$2.8\cdot10^6$	$1.3\cdot10^6$	$5.8\cdot10^6$	$1.8\cdot10^4$	$1.5\cdot10^6$	$1.5\cdot10^6$	$7.5\cdot10^6$
Year of $ value	1975	1975	1980	1975	1975	1974	1977	1977	1975
Electricity c/kWh	1.6	1.5	2.7	1.5	1.45	1.35	2.0	2.0	1.45
kWh/m^3H_2	4.75	4.4	4.5	5.0	4.5	4.5	4.65	4.15	3.5
$\eta_{electrolysis}$ %	75	80	79	71	79	79	76	85	101
η_{total} %	72	77	76	68	76	76	73	82	98
Cost of H_2 c/Nm^3 capital	2.5	3.05	4.95	5.45	2.95	2.2	3.45	2.1	2.35
electricity	7.8	6.8	12.5	7.7	6.7	6.25	9.6	8.55	5.25
other running costs	0.7	1.2	1.2	0.6	1.5	0.8	0.5	0.4	1.2
total	11.0	11.05	18.65	13.75	11.15	9.25	13.55	11.05	8.8

* Advanced alkaline process.

** IEA refers to data given within the joint IEA-project.

5.3.2.2 Solid polymer electrolysis (SPE)

Contrary to conventional alkaline electrolysis, SPE cells use an acidic medium as the electrolyte. Acidic mediums are too corrosive to be used for electrolysis in the liquid state. The availability at the beginning of the seventies of a solid polymer, Nafion, with strongly acidic properties started the development work, which has mainly been performed by General Electric. Up to now the new cells have only been studied on a pilot plant scale, but large plants are expected to be in operation in the latter half of the eighties.

The polymer material, Nafion, is a perfluorinated sulphonic acid, which has many of the characteristics of Teflon. It is remarkably resistant to heat and oxidation, and behaves like a cationic ion exchange membrane. When saturated with water, the polymer becomes an excellent ionic conductor, providing low electrical resistance.

Since the optimum current densities as well as the price of Nafion are high, the polymer material in electrolysis cells is used as a very thin sheet (optimum thickness 0.025 - 0.03 cm). It is the only electrolyte required; there are no free acids or alkalis in the system. Ionic conductivity is provided by hydrated hydrogen ions, which move through the sheet from one sulphonic acid group to another. Because the system is solid with the acid groups fixed, the acid concentration within the electrolyte is constant throughout.

The electrodes can obtain a simple arrangement in an SPE cell. They are not required to retain or support the electrolyte, and can therefore be optimized for catalytic activity and minimum cost. Platinum black powder, hot-pressed to the membrane, is used as a cathode and provides a rapid hydrogen ion exchange. A similar proprietary catalyst forms the oxygen electrode with current collectors of niobium or titanium pressed against the catalytic layer. Oxygen reacts less fast with the anode than is the case for the cathode. A minor overvoltage is therefore established.

Purified water is supplied to the anode compartment and partly moves across the membrane with the hydrogen ions. Part of the hydrogen evolved at the cathode crosses the membrane and recombines with oxygen, thereby reducing the current efficiency to about 94 % instead of the nearly 100 % which is valid for alkaline cells. Because of the high activity of the precious metal catalysts, the voltage efficiency is high and more than compensates for the lower current efficiency.

An SPE cell can be operated at pressures up to 20 MPa, and temperatures as high as 150°C are anticipated to be attainable in the future. Total electrical efficiencies of $\geq$ 100 % are, therefore, an ultimate goal of the present development work. As has been mentioned, high current densities are a prerequisite to optimize the economy and compensate for high priced cell materials. According to prognosis, high temperature cells are expected to operate in the eighties at 10000 A/m^2 and with an electricity requirement of about 3.5 kWh/Nm^3H_2.

Cost data projections for the large-scale production of hydrogen by SPE are collected in Table 5-7. The same transformation of the original figures to a more common basis was used as for the data given in Table 5-6.

As is to be expected due to decreased capital investment costs, the electricity cost element dominates the price picture more than for alkaline electrolysis, with cost percentages between 73 - 86. An exception is obtained when off-peak power is available. Presumably, production costs will be appreciably lowered when electricity efficiency up to 100 % is attained.

Table 5-7

Anticipated operating costs for SPE plants (US $).

	Ref 7	Ref 8	Ref 12	Ref 13	Ref 14	IEA*
Capital investment $\$/kW_{el}$	180	160	105	65	125	200
Plant capacity Nm^3H_2/day	$2.8 \cdot 10^5$	$2.8 \cdot 10^6$	$3.7 \cdot 10^5$		$3.6 \cdot 10^4$	$1.5 \cdot 10^6$
Year of $ value	1975	1980	1980	1978	1975	1977
Electricity						
c/kWh	1.5	2.7	2.1	2.0	1.0**	2.0
kWh/m^3H_2	4.3	4.35	4.3		3.6	4.0
$\eta_{electrolysis}$ %	82	81.5	82		98	89
η_{total} %	79	78	79		95	86
Cost of H_2 c/Nm^3						
capital	1.4	1.35	0.85		0.85	1.5
electricity	6.5	11.75	9.0		3.6	8.0
other running costs	1.0	0.9	0.65		1.0	0.4
total	8.9	14.0	10.5	8.4	5.45	9.9

* Refers to data given within the joint IEA-project.

** Off-peak power.

5.3.2.3 Solid oxide electrolysis

Significant improvements in cell efficiency can be achieved by steam electrolyzing at high temperatures. The thermoneutral potential is lower in the vapour phase. The heat required for the evaporation can be provided by waste heat instead of expensive electrical energy. The reversible potential, i.e. the free energy requirement, decreases with temperature and is about 0.9 V at 1000°C (vapour phase), which means a theoretical electrical energy requirement that is about 25 % less than at ambient temperature. The heat needed ($T\Delta S$) for an endothermic electrolysis reaction below the thermoneutral potential can be supplied by internal resistivity losses in the cell or by direct heat input from a cheap external heat source.

The principal advantage of operating at high temperatures is to improve reaction kinetics at the anode, i.e. to reduce polarization losses. Current densities > 10000 A/m^2 can thus be adopted, and the limited amount of heat evolved due to the internal resistance is mainly regained as the necessary endothermic heat.

The electrolysis of high temperature steam requires a very resistant solid electrolyte system which also works as a separating membrane between the electrode compartments. Stabilized ZrO_2 ceramics have been found to be suitable materials. During electrolysis, steam is split on the cathode side with hydrogen enriched in the steam flow, while the oxygen ions pass through the membrane and are discharged as O_2 at the anode.

Electrodes must be made of a porous material with high conductivity and resistance to the environment. The only feasible materials for the anode in its oxidizing surroundings are noble metals and oxides. The former are less desirable for large-scale applications because of their high cost. However, yttria-stabilized zirconia has suitable properties and has been successfully used. Metallic nickel or cobalt are possible cathode materials.

Development work on solid oxide electrolysis is for the present only carried out on a laboratory scale. Mean voltages of 1.3 V at current densities of about 4000 A/m^2 are achieved. Though promising in inherent properties, many difficult problems must first be solved before the new method can be tested on an applied technical scale. Large-scale applications can hardly be anticipated until the beginning of the next century. It has been proposed that a high temperature reactor should be used both for the generation of the electricity and for the supply of extra heat. The feed water to the electrolytic cells is preheated, evaporated and superheated to high temperature steam by means of heat exchangers. An overall efficiency of 41 % for hydrogen production has been calculated, i.e. almost doubled compared to the electrolysis technique of today.

Cost calculations for solid oxide electrolysis must be highly hypothetical. Capital costs are probably significantly reduced due to increased power densities. An investment limitation to about 200 \$/kW_{el} is assumed to be possible. The electricity efficiency is assumed to be increased to less than 3.5 kWh/m^3H_2. Using the same basis for cost calculations as those discussed in 5.4, a hydrogen production cost of c. 60 cr/GJ in the year 2025 is obtained. An approximate extrapolation of the hydrogen price in 1974 cost values as estimated by Bockris (15), 2.05 \$/GJ, leads to an apppreciably lower cost, c. 36 cr/GJ.

5.3.2.4 Other electrolytic processes

Large supplies of pure water are required for the electrolytic production of hydrogen, but these are rather scarce in many parts of the world with otherwise ideal conditions for large plants. Tropical island and desert regions with an abundant supply of solar power and/or ocean thermal gradients as primary sources for electricity production have for example been proposed as centres for internationally owned giant hydrogen factories.

Sea water would be an unlimited source of the raw material but is unfortunately not suitable as such. It normally contains about 3.5 % NaCl and smaller quantities of other dissolved salts. When such a dilute solution is electrolyzed, various reactions are possible, among them the following:

$$H_2 \rightarrow H_2 + \tfrac{1}{2} O_2$$

$$2H_2O + 2NaCl \rightarrow 2NaOH + Cl_2 + H_2$$

In practice, both reactions occur together. Hydrogen is evolved at the cathode and a mixture of varying compositions of oxygen and chlorine at the anode. The environment in the anode compartment becomes very corrosive and makes the selection of anode materials very critical. Moreover, the chlorine evolved presents a severe disposal problem, unless means of utilizing the gas can be found.

Much research has been directed towards the suppression of chlorine evolution (16). The nature of the electrode mechanism and of the transport effects is not yet fully known.

The thermodynamic potential for an H_2-Cl_2 cell in sea water is between 1.8 - 2.2 volts and increases with increasing current density due to a simultaneous increase in pH. The potential of an H_2-O_2 cell at STP is between 1.25 - 2.05 volts, as has already been discussed, and it depends in the same way on current density and hence pH. At potentials above 2.2 volts, the rate of Cl_2 evolution becomes limited due to transport phenomena, and O_2 evolution becomes the predominating reaction in sea water electrolysis. However, the range is not practical for economical reasons, due to high internal cell resistance and thus high heat losses. Efforts must instead be directed to the achievement of practically applicable O_2 evolution rates at a potential of < 1.8 volts (STP), which has not yet been attained.

One reason for this is that the conductivity of sea water is very low. Consequently, the resistance of an electrolysis cell is too high for the process to be considered as a commercial means of hydrogen production. There are two potential ways of overcoming this problem, either by concentrating sea or brackish water into a brine or by adding a supporting electrolyte, such as NaOH. In the first case, oxygen evolution is completely suppressed, and the chlorine producing reaction becomes dominant. This process, the chlorine-alkaline process, is also used by for example the Swedish pulp industry for the large-scale production of chlorine and caustic soda. Hydrogen is obtained as a by-product. The process cannot be regarded as a means for the production of hydrogen on the scale discussed in this study, as the demand for chlorine and soda is too limited (see Chapter 8).

The other alternative, the addition of NaOH, is only slightly more attractive as its concentration will automatically increase during cell operation to a point when it has to be dumped from the cell.

The electrolysis of sea water to produce hydrogen alone cannot be regarded as a practical proposition. If sea water is the only available source of water it is more practical and economic to desalinate it. The cost of desalinating sea water to drinking standards is in the range of 1 - 2 cr/m^3 and adds only about 0.2 - 0.4 % to the cost of hydrogen production ($\sim$ 12.7 GJ H_2/m^3 H_2O). However, a higher standard is required for water electrolysis. Quite small levels of impurities result in the continual accumulation of the impurities in the cell, which can lead to increased corrosion, the onset of side reactions and the contamination of the cell membrane. In general, feed water must be purified to a level approximating that of distilled water, and this is usually performed by ion exchange demineralization. The total cost for the purification of sea water to feed-water standard does not amount to more than 2 - 3 % of the production cost for hydrogen.

5.3.3 Thermochemical methods in open systems

Open systems are technically simple to operate. Temperatures and pressures are usually limited to specifications where abundantly available materials like ordinary or stainless steel can be used and fairly high losses of circulating raw materials and products are acceptable. Most conventional plant processes are of this type. Nearly all the present-day hydrogen production is obtained in such processes, with either natural gas and petroleum products or coal as the feed material (Table 5-1). Biomass and organic wastes are potentially possible future raw materials of great significance. Hydrogen can also be produced by the interaction of water vapour with reactive metals like iron and chemical compounds of sulphur and phosphorus or by the direct splitting of compounds containing hydrogen like methanol and ammonia, which can be produced cheaply in large amounts.

The principal steps in manufacturing processes are shown schematically in Figure 5-6.

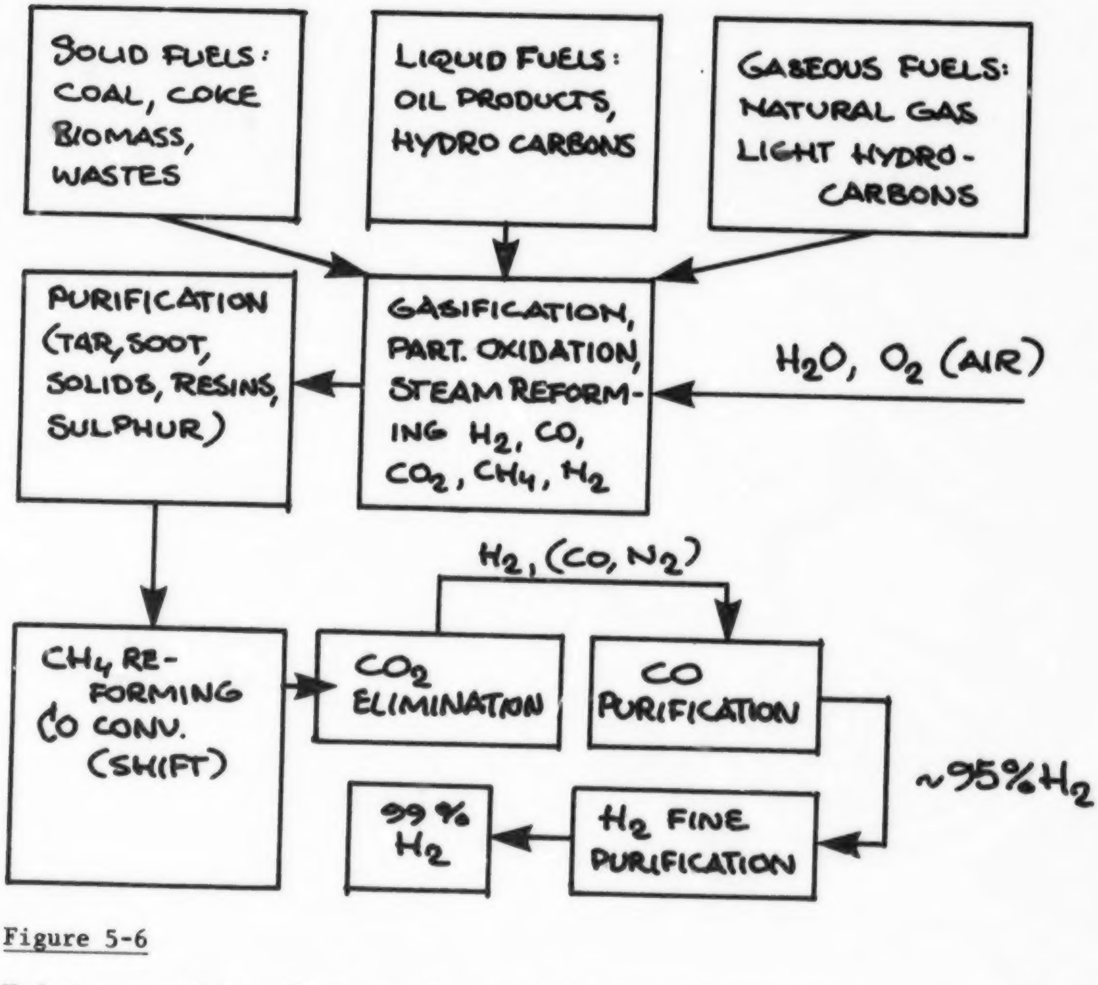
SOLID FUELS: COAL, COKE BIOMASS, WASTES
LIQUID FUELS: OIL PRODUCTS, HYDRO CARBONS
GASEOUS FUELS: NATURAL GAS LIGHT HYDRO-CARBONS
PURIFICATION (TAR, SOOT, SOLIDS, RESINS, SULPHUR)
GASIFICATION, PART. OXIDATION, STEAM REFORMING H_2, CO, CO_2, CH_4, H_2
H_2O, O_2 (AIR)
H_2, (CO, N_2)
CH_4 REFORMING CO CONV. (SHIFT)
CO_2 ELIMINATION
CO PURIFICATION
~95% H_2
99% H_2
H_2 FINE PURIFICATION

Figure 5-6

Hydrogen manufacturing steps from oil and biomass products.

5.3.3.1 Petroleum and natural gas

The principal processes applied on an industrial scale for the production of hydrogen are:

- steam oxidation (methane, natural gas, naphta)
- partial oxidation (heavy natural and residual oils)
- dehydrogenation (ethane, butane)
- thermal or catalytic cracking (gaseous hydrocarbons)

At present, petroleum and natural gas are the completely dominating feedstocks for hydrogen production (Table 5-1). The captive gas is both produced and consumed by the petroleum refining industry. The consumption is primarily for hydro-desulphurization of petroleum streams and for hydrocracking of heavy petroleum fractions to yield high quality petrol. However, the demand is expected to increase substantially because of accelerated hydro-treating requirements in three areas, namely the increased demands for distillates (residual fuels), heavier crude oil fractions with higher sulphur content, and higher environmental regulations on SO_2 emission. According to three independent American investigations, the cumulative demand for hydrogen in the US during the period 1975 - 2000 is expected to require that if NG or crude oil are the sole feedstocks, 20 % of all available NG or 10 % of the crude oil supply should be earmarked for hydrogen production. This is of course unacceptable considering other urgent demands for the two primary energy sources, and it emphasizes the need for new hydrogen feedstocks.

The majority of existing hydrogen generators in the refineries are based on steam reforming of natural gas or naphta. The primary step is the endothermic steam-hydrocarbon reaction:

$$CH_4 + H_2O \rightarrow CO + 3H_2 \text{ (NG);}$$

$$CH_{2.2} + H_2O \rightarrow CO + 2.1H_2 \text{ (naphta);}$$

followed by the exothermic shift reaction:

$$CO + H_2O \rightarrow CO_2 + H_2$$

For NG, half of the hydrogen produced is derived from steam and half from methane, while for naphta water supplies about 64 % of the hydrogen. The process is illustrated schematically in Figure 5-7. A more detailed flow scheme is given in Figures 5-8 and 5-9. The PSA step (pressure swing adsorption) is a recently developed purification step to increase the purity of the raw hydrogen product from about 95 % to > 99 % by means of molecular sieves.

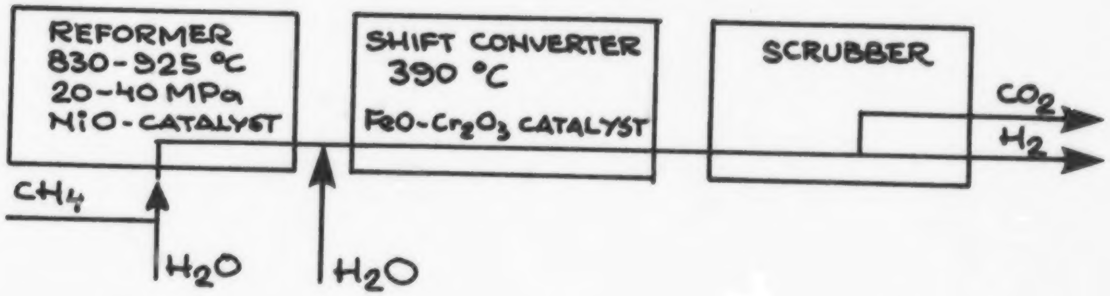
REFORMER
830-925 °C
20-40 MPa
NiO-CATALYST
SHIFT CONVERTER
390 °C
FeO-Cr_2O_3 CATALYST
SCRUBBER
CO_2
H_2
CH_4
H_2O
H_2O

Figure 5-7

Steam reforming process for methane.

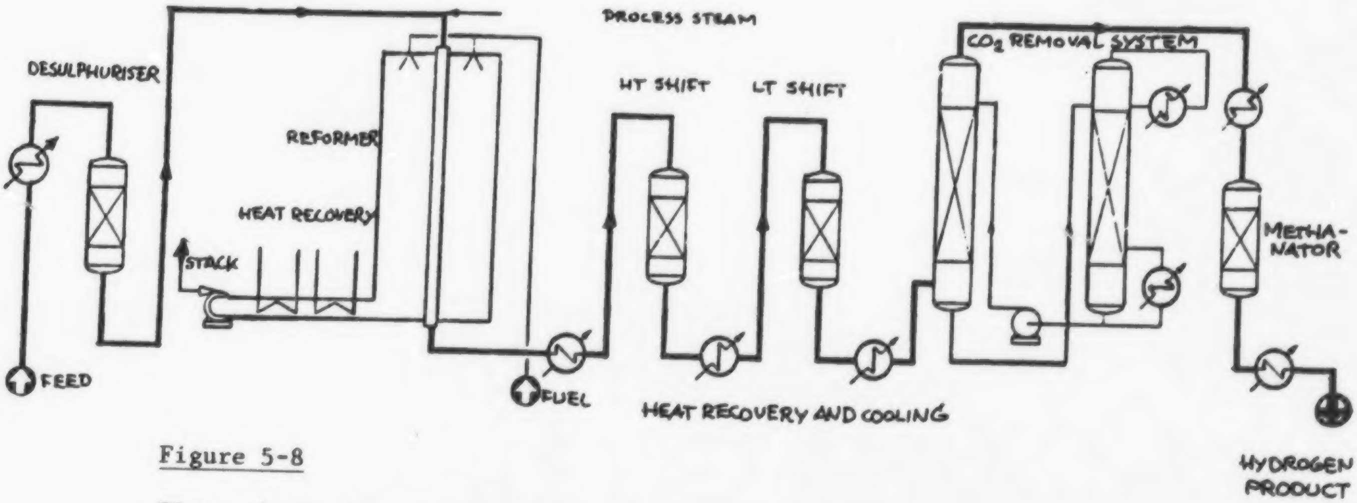
PROCESS STEAM
DESULPHURISER
REFORMER
HEAT RECOVERY
STACK
FEED
FUEL
HT SHIFT
LT SHIFT
CO_2 REMOVAL SYSTEM
METHA-NATOR
HEAT RECOVERY AND COOLING
HYDROGEN PRODUCT

Figure 5-8

Flow scheme for a conventional hydrogen plant (17).

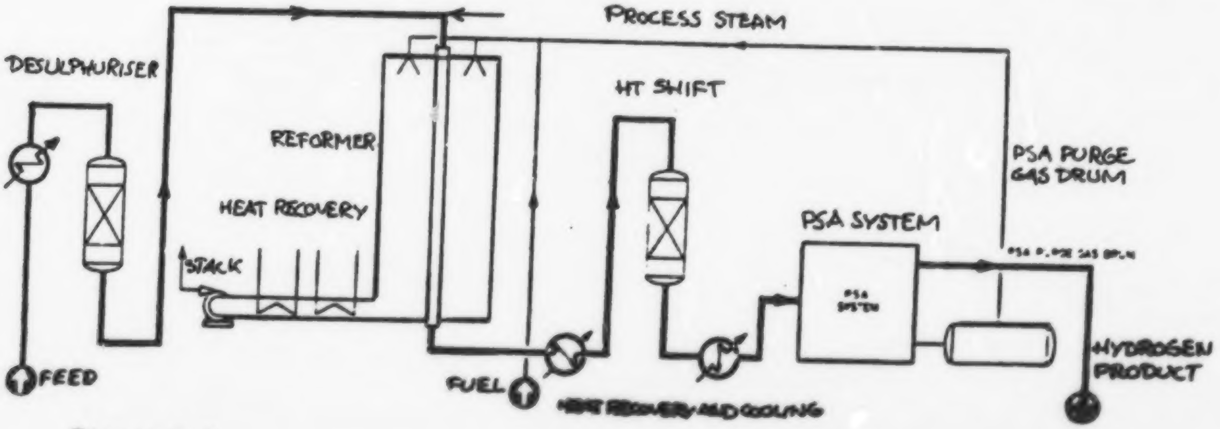
PROCESS STEAM
DESULPHURISER
REFORMER
HEAT RECOVERY
STACK
FEED
FUEL
HT SHIFT
HEAT RECOVERY AND COOLING
PSA PURGE GAS DRUM
PSA SYSTEM
HYDROGEN PRODUCT

Figure 5-9

Flow scheme for a PSA hydrogen plant (17).

The extra heat required is supplied by the combustion of NG or naphta. The gas is purified from sulphur compounds to a level of less than 5 ppm before being introduced into the reformer. The scrubbing process reduces or eliminates the diluting CO_2 by its absorption in amine solution or in cold methanol, or most efficiently in liquid nitrogen. The efficiency (energy output:input) is 70 - 75 %.

Heavy oils cannot be processed catalytically like the lighter feedstocks because they cannot be completely vapourized without carbon formation and because of their relatively high sulphur and ash contents. The oils are instead subjected to partial oxidation in the presence of reformer steam. High-purity oxygen must be used for the combustion in a process according to Figure 5-10 because of the difficulty of separating nitrogen from hydrogen in the scrubber steps.

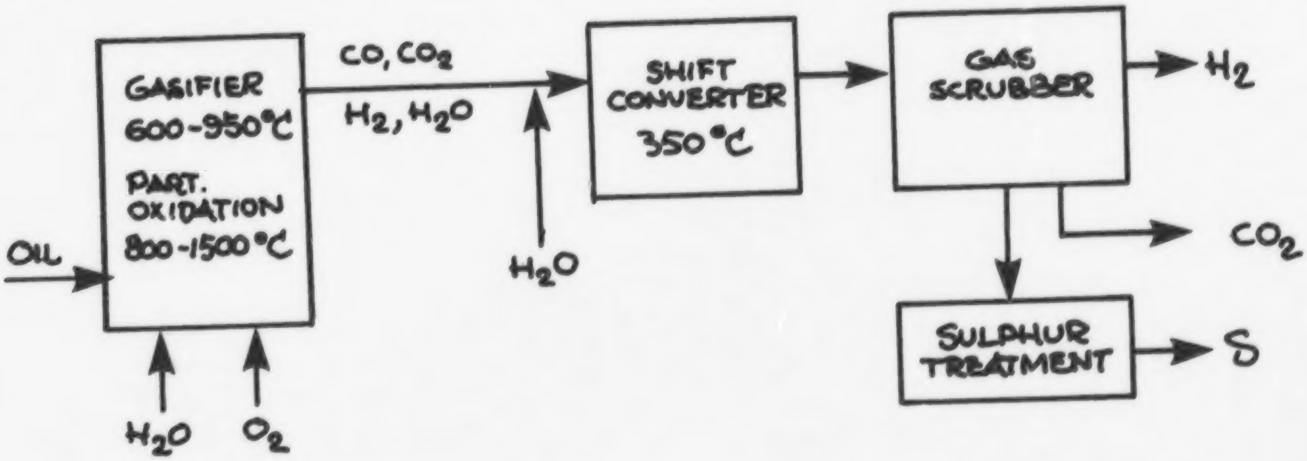

Figure 5-10

Partial oxidation process for heavy oils.

The reformer reaction for an oil of average composition is

$$CH_{1.8} + H_2O \rightarrow CO + 1.9H_2$$

and is followed by the shift reaction.

Water supplies about 70 % of the hydrogen. The necessary energy to drive the first reaction is about 40 % greater than that for light hydrocarbons and is obtained from the combustion. The overall reaction for a comletely shifted process is

$$CH_{1.8} + 0.98H_2O + 0.51O_2 \rightarrow CO_2 + 1.87H_2$$

and the efficiency is about 64 %.

Capital costs are much higher than those of the steam reforming process due to additional costs for oxygen and the desulphurization step.

The other two processes for hydrogen production mentioned earlier are of minor importance. Dehydrogenation is thermodynamically disadvantageous compared to the methods discussed earlier because of the greater bonding strength of C-H by comparison with that of C-C. The reaction is only possible in the presence of oxide catalysts like Al_2O_3 stabilized by Cr_2O_3, which suppress the splitting of the carbon bond. The process is mainly used for the dehydrogenation of ethane to ethylene and of butane to diolefins. Hydrogen is obtained as a by-product with a yield of about 20 %. Above 600°C, the thermal splitting of the carbon bond competes with the dehydrogenation and becomes the cause of a less pure product mixture. Thermal cracking can also be applied for the splitting of petrol and heavy oils to a synthetgas with a high hydrogen content.

Results of an analysis of published literature data on cost elements for the large-scale production of hydrogen (> 10^6 m^3/day) by means of steam reformation and partial oxidation are summarized in Table 5-8. To make the table more comparable, the figures have been transformed to a common basis by applying the method used for Table 5-6, i.e. an annuity of 15 % and a load factor of 90 %. The process efficiency is expressed as the ratio of output energy to input energy.

Production costs are escalating very rapidly during the observed period, more rapidly for capital costs than for running costs. However, the feedstock dominates the cost picture and varies between 70 - 90 % for steam reformation and between 55 - 85 % for partial oxidation.

Table 5-8

Hydrogen production costs from NG and oil (US $).

	Steam reformation				Partial oxidation		
Reference	(1)	(10)	(18)	(8)	(1)	(18)	(8)
Capital invest. c/m^3H_2/year	0.86	2.80	6.24	6.2	2.54	9.2	17.0
Year of $ value	1975	1975	1978	1980	1975	1978	1980
Process efficiency	0.75	0.75	0.75	0.75	0.70	0.60	0.65
Feedstock	NG	NG	NG	NG	oil	oil	oil
$/GJ	0.85	1.0	1.85	2.70	1.39	2.0	2.05
Product cost c/m^3							
capital	0.13	0.42	0.93	0.93	0.38	1.38	2.55
feedstock	1.44	1.70	3.15	4.60	2.54	4.26	4.03
other running costs	0.05	0.10	0.42	0.31	0.10	0.65	0.90
Σ	1.62	2.22	4.50	5.84	3.02	6.29	7.48

5.3.3.2 Coal (gasification)

The production of hydrogen from coal is basically a partial oxidation process simular to that for heavy oil and occurs in accordance with the schematic flow-sheet given in Figure 5-10. The process is complicated by the necessity of handling a relatively unreactive fuel and removing large amounts of ash. Coal is introduced into a gasifier where it is reacted with steam and oxygen to form a gas mixture of H_2, CO and CO_2 as well as minor volumes of hydrocarbons and H_2S. After being cleaned from solid products like ash and tar, the gas mixture is scrubbed to remove H_2S and CO_2, sent to a combination of shift reactors and finally cleaned to the required hydrogen purity in a last scrubbing step.

The reactions in the gasifier are a mixture of direct carbon oxidation, steam reduction by carbon and CO, and methanation. The reaction paths are governed by applied temperatures and pressures. Water supplies on average about 80 % of the hydrogen produced, and energy requirements are less favourable than for production methods using oil products. Current technical applications of coal gasification processes are mainly centered to Europe (see Table 5-1), South Africa and India. A great many variations of the gasification step have been developed and are used in industrial processes or tried in development schemes. The gasification is a heterogeneous reaction and requires temperatures above 700°C under a supply of large amounts of heat. The raw gas produced contains varying amounts of H_2, CO, CO_2, CH_4, N_2 and H_2S depending on the temperature, pressure, type of raw coal and added gas mixture. The gasification can be performed on a fixed bed (e.g. the Lurgi Process), a fluidized bed (e.g. Hygas) or in an entrained phase (e.g. Koppers-Totzek, K-T), and the necessary heat can be supplied either directly by oxygen or heat carriers, or indirectly through heat transferring walls.

Development work is also being carried out on in-situ coal gasification. Air or oxygen (with or without steam) is injected directly into the ground and supports combustion of a coal seam. The resulting gases are brought to the surface for further processing.

The raw product gas is converted in subsequent shift reactions and scrub stages to the desired product, which can be either hydrogen of 92 - 97 % purity or two product streams, one containing purified hydrogen and the other a gas mixture with burnable components (CO, hydrocarbons) which can be used for power generation. The Hygas Process, which is discussed further in 5.3.3.4, is an example of the latter which has the advantage of potentially high total thermal efficiencies (~ 80 %). Normal efficiencies vary between 55 - 70 %.

The following economic evaluations are concentrated to the K-T process, which is applied commercially in more than 15 large plants. The process, Figure 5-11, has the ability to handle a large variety of feedstocks including all sorts of coal, tars, heavy residues and oils. It is simple in construction and highly reliable because of the lack of mechanical complexity. Pulverized coal is injected in an entrained phase together with oxygen and steam into the gasifier and burned with high speed at temperatures of about 1600°C and at pressures slightly above atmospheric. Consequently the raw product gas does not contain any tar or phenols and only a small amount of methane. The need for subsequent compression before further treatment and delivery of the synthesis gas is a drawback which might be overcome in new developments of the basic K-T process. At present its efficiency lies between 50 and 65 %.

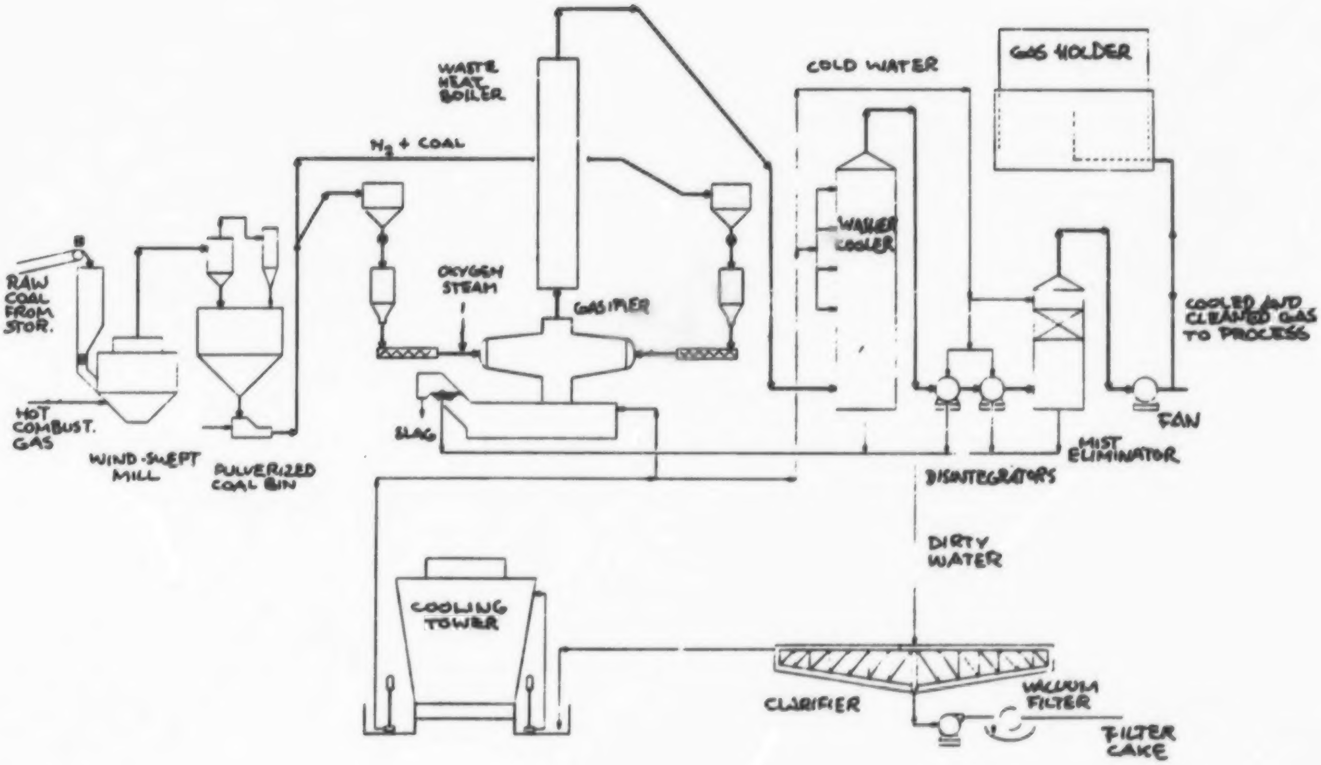
WASTE HEAT BOILER
N_2 + COAL
COLD WATER
GAS HOLDER
WASHER COOLER
RAW COAL FROM STOR.
OXYGEN STEAM
GASIFIER
COOLED AND CLEANED GAS TO PROCESS
HOT COMBUST. GAS
SLAG
FAN
WIND-SWEPT MILL
PULVERIZED COAL BIN
MIST ELIMINATOR
DISINTEGRATORS
DIRTY WATER
COOLING TOWER
CLARIFIER
VACUUM FILTER
FILTER CAKE

Figure 5-11

K-T gasification system - simplified flow diagram.

The cost evaluations, presented in Table 5-9, are based on the same general assumptions and methods as those used for the calculation of Table 5-8.

The same general trend of rapidly escalating capital costs as observed earlier is apparent, which leads to a decrease in the feedstock cost share from 54 % to 22 - 32 %.

Table 5-9

Hydrogen production costs in K-T processes (US $).

Reference	(7)	(1)	(19)	(18)	(8)	(8)*
Capital invest. c/m^{3}H$_2$/year	7.9	3.65	37.6	17.8	25.5	20.2
Year of $ value	1974	1975	1977	1978	1980	1980
Process efficiency	0.66	0.55	0.6	0.51	0.6	0.64
Coal $/GJ	0.90	0.90	0.90	1.32	0.94	0.94
Product cost c/m^3 capital	1.19	0.55	5.64	2.66	3.82	3.02
feedstock	1.74	2.09	1.92	3.30	2.00	1.87
other running costs	0.30	0.30	1.17	1.26	1.13	0.92
Σ	3.23	2.94	8.73	7.22	6.95	5.79

* Developed K-T process

5.3.3.3 Biomass and organic wastes

Biomass, i.e. plant material in any form from algae to wood, has a remarkably uniform energy content, 16 - 25 GJ/ton dry material. During photosynthesis, light energy from solar radiation (on average over the year 0.1 kW/m^2 in Sweden) is captured and used to convert water and carbon dioxide into oxygen and energy-rich carbohydrates. The dominating radiation used for the photosynthesis has a wavelength of 400 - 700 nm, and this is converted to plant biomass with an efficiency of about 9 %. Due to losses such as photorespiration, maximum practical yields are 5.5 - 6 %, normal yields in plant cultivation are 2 - 4 %, and in wild free-growing plants and trees the figure is 0.5 - 1.5 %. Some data on yields obtainable from the cultivation of various crops suggested as future energy sources are summarized in Table 5-10. The wide variation limits depend on geographical position, climate, number of hours of sunshine etc. Mean values are approximately valid for Sweden.

Table 5-10

Farming yields and energy contents of various crops per dry weight.

Species	ton/hectare	GJ/ton
Maize	12 - 15	
Wheat	3 - 8	
Sugar cane	30 - 90	
Sunflowers	25 - 50	
Poplar	16 - 25	
Forests	2 - 7	17 - 21
Eucalyptus	20 - 60	
Algae	35 - 75	21 - 25
Giant sea kelp	30 - 60	
Water hyacinth	35 - 70	

The average daily production of community wastes in a highly industrialized country like Sweden is about 2 kg/inhabitant, half of which is of organic type. Thus the total annual production of wastes which can be used as an energy source is about 3 Mton. The annual productivity of our forests is about 10 times higher, i.e. ~ 90 Mm^3 or 30 - 35 Mtons dry weight. About 80 % of the annual regrowth is used in the pulp industry. The other 20 % (stumps, tops, branches) is mainly left in the forest, and if economically realizable this is a potential future energy source. Today about 8 % of the total Swedish energy consumption is obtained from biomass, mainly from wastes in the wood and pulp industries (Chapter 8).

Biomass and organic wastes can be converted to useful energy and energy carriers by various processes, Figure 5-12. Direct combustion is the most generally applied method. Gasification can be accomplished by partial oxidation according to modifications of the processes earlier discussed in 5.3.3.2.

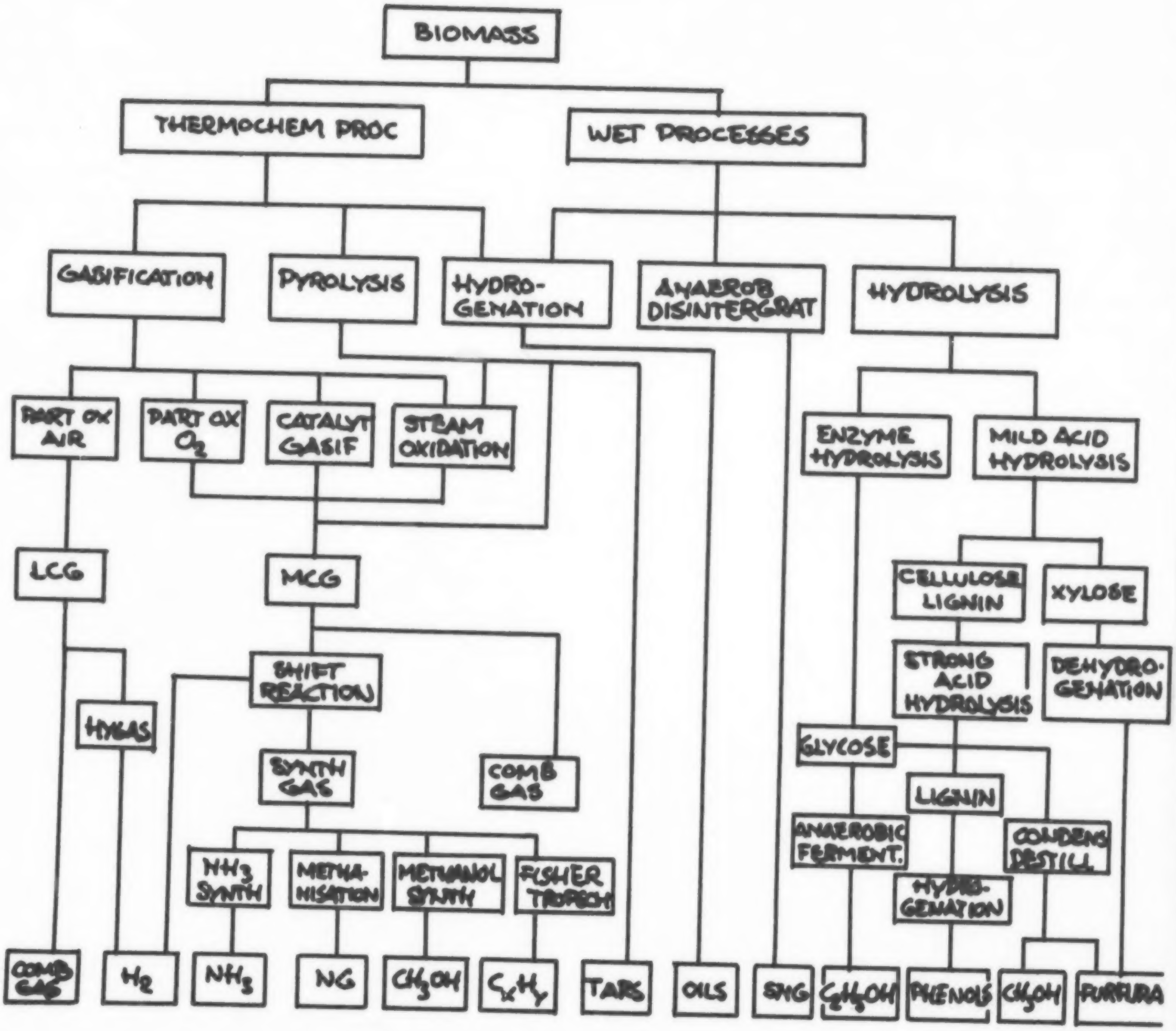
BIOMASS
THERMOCHEM PROC
WET PROCESSES
GASIFICATION
PYROLYSIS
HYDRO-GENATION
ANAEROB DISINTERGRAT
HYDROLYSIS
PART OX AIR
PART OX O_2
CATALYT GASIF
STEAM OXIDATION
ENZYME HYDROLYSIS
MILD ACID HYDROLYSIS
LCG
MCG
CELLULOSE LIGNIN
XYLOSE
SHIFT REACTION
STRONG ACID HYDROLYSIS
DEHYDRO-GENATION
HYGAS
GLYCOSE
SYNTH GAS
COMB GAS
LIGNIN
ANAEROBIC FERMENT.
CONDENS DESTILL
NH3 SYNTH
METHA-NISATION
METHANOL SYNTH
FISHER TROPSCH
HYDRO-GENATION
COMB GAS
H2
NH3
NG
CH3OH
CxHy
TARS
OILS
SNG
C2H5OH
PHENOLS
CH3OH
FURFURA

Figure 5-12

Conversion of biomass to chemical products or energy carriers. LCG = low caloric gas; MCG = medium caloric gas.

Pyrolysis is another method which was in general use in Sweden during the last world war to generate wood gas as a car fuel from wood. The Ferrugas process (20) is a recently developed Swedish hybrid of the Steam-Iron process, discussed in 5.3.3.4, and converts wood in a combined pyrolysis-steam gasification process. Finely divided biomass is fed into the reduction zone of the reactor which also contains magnetite, Fe_3O_4. At a temperature of 900°C, the biomass is momentarily pyrolyzed to a mixture of $H_2O + CO + C$ at the same time as the carbon formed reacts with steam to form $H_2 + CO$, and the carbon oxide formed is oxidized to CO_2 by magnetite. After a purification step, a pure hydrogen product gas is obtained.

Biomass and organic wastes can also be disintegrated to a biogas mixture by enzymatic hydrolysis, anaerobic or liquor fermentation catalyzed by microorganisms, and anaerobic digestion. Intermediate fuels, such as alcohols, can also be produced in these processes.

The product gas of all gasification reactions is a mixture of CH_4, H_2, H_2O, N_2 and carbon oxides, usually with a low caloric heat content. The gas mixture can be further purified by shift reactions and purification steps to pure hydrogen or a high caloric gas with a dominating methane content. Special chemicals like methanol and ammonia can also be produced. The energy conversion efficiency is between 50 and 60 % in hydrogen and SNG production, which can be compared with efficiencies of 38 - 45 % and 55 - 62 % for the production of methanol and ammonia, respectively.

No reliable cost figures for the production of hydrogen from biomass or community wastes have been found in the available literature. An approximate calculation, Table 5-11, for the large scale production of hydrogen ($3 \cdot 10^8$ m^3/year; purity 97 %) has been based on cost data given for the Ferrugas process discussed earlier (20); these data have been transformed according to the financial rules valid for this study, i.e. 1978 crown value, a real interest of 4 % and a depreciation time of 10 years. It is further assumed that the raw product, biomass, obtained from rapid-growing energy forests, has a heat content of 17 GJ/ton. The annual plant load is 90 % and the efficiency of the process is 45 %.

Table 5-11

Hydrogen production cost in a Ferrugas process.

	1978	1985	2005	2025
Capital investments cr/m^3H_2/year	0.50	0.50	0.50	0.50
Biomass cr/GJ	14.7	15.1	16	17
Product öre*/m^3H_2				
capital	6.2	6.2	6.2	6.2
feedstock	41.7	42.8	45.4	48.2
other running costs	5	6	8	10
total	52.9	55.0	59.6	64.4
total cr/GJ	41.4	43.1	46.7	50.4

* 1 öre = 0.01 cr.

5.3.3.4 Other reduction methods

Pure water or aqueous solutions of acids and alkalis react spontaneously or under the influence of catalysts with many elements, with liberation of hydrogen gas. Such elements are for example the alkali and alkaline earth metals, zinc, copper, iron, phosphorus and sulphur. Sulphides can also give off H_2 in the presence of O_2. The reactions are used on a laboratory scale for the production of pure H_2 but they are not economically feasible on a larger scale as long as the metal or the metallic compound is stoichiometrically consumed.

The Steam-Iron process is a three-step chemical process for the production of hydrogen of purity > 96 % from any type of coal, Figure 5-13. In the first step, coal is gasified at a temperature of about 1050 - 1100°C with steam and air to produce a gas rich in CO and H_2. This gas is reacted with iron oxides (magnetite) in the reductor step to produce reduced forms of iron oxides. These are then reoxidized by steam to the original magnetite form in the third step. The hydrogen gas simultaneously evolved has a high purity and needs only clean-up to remove sulphur and small amounts of carbon monoxide. The spent reducing gas contains considerable thermal energy and is used to produce electricity. The steam-iron reactor is operated at about 830°C. The process can be operated at any pressure, but to realize the full potential of energy recovery a pressure of between 1.7 and 3.0 MPa is normally chosen.

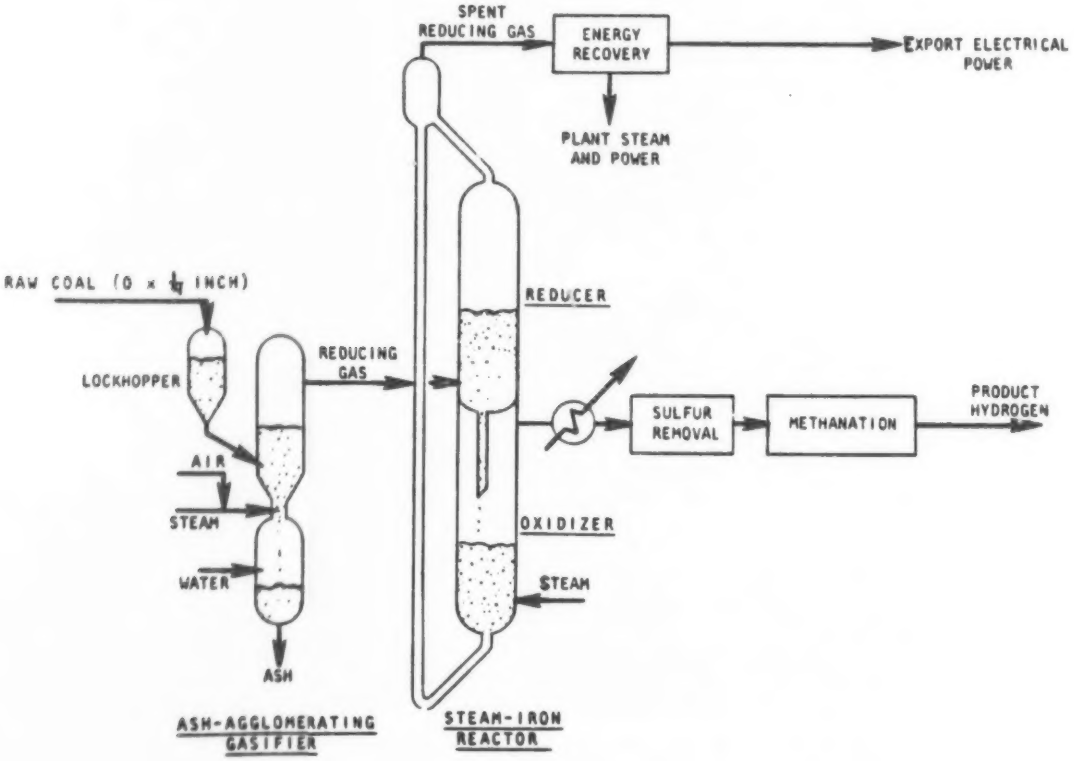
SPENT REDUCING GAS
ENERGY RECOVERY
EXPORT ELECTRICAL POWER
PLANT STEAM AND POWER
RAW COAL (0 × ¼ INCH)
REDUCER
LOCKHOPPER
REDUCING GAS
AIR
STEAM
WATER
ASH
SULFUR REMOVAL
METHANATION
PRODUCT HYDROGEN
OXIDIZER
STEAM
ASH-AGGLOMERATING GASIFIER
STEAM-IRON REACTOR

Figure 5-13

Hydrogen production by the Steam-Iron process (21).

5.3.3.5 Dissociation of chemical compounds

Chemical compounds like methanol and ammonia which are mass produced at relatively cheap prices can be used as intermediary raw materials for the production of hydrogen.

Methanol can be split directly to $CO + 2H_2$ at 320 - 345°C in the presence of suitable catalyts. The reaction is strongly endothermic ($\Delta H = 128.2$ kJ/mole). The by-product CO can be converted to H_2 in a shift reaction. The process can also be achieved in one step by reacting methanol with steam at a high pressure. With the price structure of today, the cost of raw materials alone (methanol + fuel) leads to a hydrogen cost > 42 cr/GJ. The method is thus non-competitive by comparison with the methods discussed earlier for the large-scale manufacture of hydrogen.

The above is also valid for the direct splitting of ammonia:

$$2NH_3 \rightarrow N_2 + 3H_2;\ \Delta H = 92.2 \text{ kJ/mole}$$

This can be performed catalytically at 900 - 1000°C and at a pressure of about 0.3 MPa. The nitrogen formed is separated by cryogenic or sorption methods.

5.3.4 Thermochemical methods in closed systems

As has been discussed in 5.3.1, direct thermal splitting of water requires very high temperatures. Thermochemical water splitting, which is the term usually used for the methods discussed in this section, is a scheme to evade the high temperatures of direct thermal decomposition by performing the process in a closed many-step cycle. Each step is required to yield a complete exchange of reactants at a temperature acceptable from a materials point of view, i.e. < 1100 K (Figure 5-14). Water reacts chemically with other substances to yield hydrogen or new hydrogen-bearing compounds, which in turn are thermally decomposed to obtain hydrogen. The intermediate compounds are regenerated at required temperature levels. Exothermal energy evolved in intermediate process steps is used as far as possible as supplementary heat in endothermal steps. The only feedstocks required in the closed cycle are water and an external heat supply. The only products are H_2 and O_2, each of which is generated in separate steps.

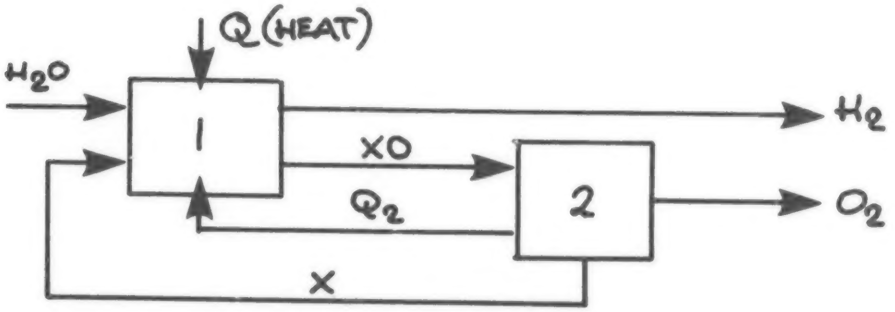

Figure 5-14

Two-step thermochemical cycle.

A plant for providing thermochemical hydrogen would comprise three major systems as illustrated in Figure 5-15. They are the heat source, the process plant and an intermediate heat-transport loop that would interface the other parts and deliver heat energy at the appropriate temperature. The heat requirements are compatible with the characteristics of a high temperature reactor (HTR) with a helium coolant but also with other sources, such as for example solar energy concentrators.

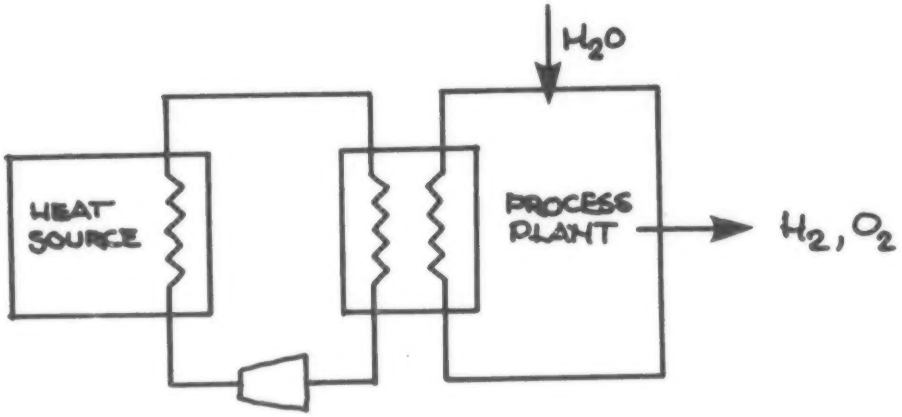

Figure 5-15

Thermochemical plant.

The laws of thermodynamics restrict the efficiency that can be achieved and the performance of the water splitting process. One of the requirements that must be met is that the sum of the enthalpies ΔH must equal or exceed the enthalpy of formation of water. According to the second law of thermodynamics the free energy change

$$\Delta G = \Delta H - T\Delta S$$

where

ΔS = entropy change

T = absolute temperature

Since it is advantageous to choose a cycle with a minimum amount of work involved, i.e. a small ΔG, it follows that endothermic reactions should preferably occur at high temperatures and exothermic at low temperatures.

The selection of a thermochemical cycle is ultimately governed by economics. In choosing the elements which will be recirculated within the system in large amounts, only those of low cost are usually considered. The selection is further restricted because these elements have to be multivalent in order to chemically reduce protons to hydrogen and to convert oxide ions to oxygen. They must also easily and rapidly form stable compounds with one or both of these ions. The element that is most frequently found in proposed cycles is sulphur. Others which appear frequently are iron, the halogens, and the alkali and alkaline earth metals.

Other important aspects to be taken into consideration are the toxicity and the corrosivity of the reactants. From a separation point of view, advantages are offered by cycles dealing only with gaseous or liquid reactants. If solids are present, which is the case for several cycles now under study, technical solutions of fluidification will most probably have to be introduced into the final process.

It has been shown theoretically that three reactions are the minimum required for a viable thermochemical cycle below 1100 K. Experience has further shown that very few technically operable three-step cycles exist. However, it must be emphasized that in order to be technically feasible each separate main reaction step is usually divided into more than one part-process to achieve required separations and/or heat transitions. A way of simplifying the reaction paths is to combine electrolytic and thermochemical steps into what is called a hybrid cycle.

At least 250 different cycles have been studied briefly, and about 100 more in detail. R & D work has been done on chemical equilibrium, kinetics, heat transfer, and also in a few cases on corrosion in the environment. A few cycles, some of which will be discussed further below, have been studied on a pilot plant scale. In a few cases calculations have been made of the efficiency and the cost of a large hydrogen production plant. With the efficiency based on the relationship between the heat content of the hydrogen product and the heat delivered to the system from the primary energy source, figures have been reported ranging from less than 20 % up to about 45 %. It is believed that even higher efficiencies can be achieved. However, it might reasonably be assumed that the higher figures in particular have been based on an almost complete retrieval of exothermal heat as well as very low losses of recirculating reactants, and this will probably be difficult to achieve in actual industrial plant operations.

Before thermochemical cycles can be applied for the large-scale production of hydrogen ($> 3 \cdot 10^5$ Nm^3/h), some problems and difficulties have to be overcome:

- The technical upscaling from present-day laboratory or demonstration equipment to a full-scale plant. Reactants recirculating within the system will be of the order of 1000 tons/h, while current conventional plants have maximum product capacities of 100 tons/h.
- Interphase coupling of the heat source, e.g. an HTR reactor, to the high temperature steps of the chemical plant.
- Heat transfer at high temperatures in endothermic reactions.
- Achievement of high thermal and material efficiencies in separation steps, e.g. gas/gas or liquid/liquid.
- Metallurgical high temperature problems in strongly corrosive environments.

Of all the thermochemical cycles so far investigated, the following three have been studied fairly thoroughly on both a laboratory and a small technical scale, and they are regarded as particularly promising.

The reaction steps are given in summarized forms:

1) $2H_2O + SO_2 \rightarrow H_2 + H_2SO_4$; electrolysis

$H_2SO_4 \rightarrow H_2O + SO_2 + \frac{1}{2} O_2$; 850°C

The cycle is a hybrid sulphuric acid cycle and is usually called the "Westinghouse process" after its principal investigator (22, 23).

Complete flow sheets have been prepared for each part of the process and analyzed in detail as to the technical equipment and cost. Predicted overall efficiencies between 36 and 45 % have been reported.

2) $2H_2O + SO_2 + 4I_2 \rightarrow H_2SO_4 + 2HI_4$; 90°C

$H_2SO_4 \rightarrow H_2O + SO_2 + \frac{1}{2} O_2$; 850°C

$2HI_4 \rightarrow 4I_2 + H_2$; 300°C

This sulphur-iodine cycle has been studied by among others General Atomic since 1974 (24, 25). Engineering data and flow sheets have been developed. A test program is being performed to evaluate construction materials in the highly corrosive fluid environments. The application of HTR process heat is the object of other studies. The schedule is aimed at a first commercial plant design in 1984. The present overall efficiency estimate is 40 - 42 %.

Variations of the cycle are being studied, among others by the EEC research establishment in Ispra, where HBr is used instead of HI and the last step is performed by electrolysis.

3) $3FeCl_2 + 3H_2O \rightarrow 3FeO + 6HCl$; 480 - 760°C

$3FeO + H_2O \rightarrow Fe_3O_4 + H_2$; 440°C

$Fe_3O_4 + 8HCl \rightarrow FeCl_2 + 2FeCl_3 + 4H_2O$;

$2FeCl_3 \rightarrow 2FeCl_2 + Cl_2$; 400°C

$H_2O + Cl_2 \rightarrow 2HCl + \frac{1}{2} O_2$; 400 - 800°C

The iron-chlorine cycle exists in many modifications containing different reaction steps performed at different temperatures and studied partly or more generally in various laboratories (26). All the modifications involve one or more difficult solid phase separation steps, which is a serious disadvantage compared to the other two cycles discussed. Predicted efficiencies vary from 18 up to 50 %.

Reliable data on complete cost estimations are rather scarce in the literature. Table 5-12 summarizes some of the better estimates for a large hydrogen production plant with an annual capacity of about 10^9 m^3 and an average load of 80 %. They represent the three types of cycle described earlier. It is assumed that heat and electricity are bought from an HTR power reactor at stated prices. To make the final results mutually more comparable as well as comparable to production methods discussed earlier, capital costs have been transformed to the same annuity, 15 %. As is apparent from the table, investment estimates vary greatly and must be regarded as highly uncertain. The investments for ref (10) also include a very expensive interface heat exchanger. These authors' original calculations of "other running costs" have been reduced to more appropriate values.

Table 5-12

Operating costs for thermochemical plants (US $).

	Ref 27	Ref 10	Ref 28	Ref 27	Ref 10
Cycle type	1	1	2a	2b	3
Year of $ value	1977	1975	1976	1977	1975
Capital investment $/Nm^3H_2/year	0.17	0.56	0.20	0.18	2.63
Overall efficiency %	41.3	30	41.2	36.9	19
Energy consumption heat MJ/Nm^3	20.3	23.8	31.0	19.6	70.9
electricity kWh/Nm^3	1.11	2.0	-	1.57	-
Heat price mils/MJ	2.2	1.47	1.82	2.2	1.47
Electricity price mils/kWh	20	14.7	-	20	-
Cost of H_2 c/Nm^3 capital	2.55	8.40	3.00	2.70	39.45
heat + el	6.67	6.44	5.64	7.45	10.44
other running costs	0.67	1.50	1.50	0.74	2.50
total	9.89	16.34	10.14	10.89	52.39

1. Cycle type Westinghouse
2a. " General Atomics
2b. " sulphur-bromine (electrolysis)
3. " iron-chlorine (Mark 15)

5.3.5 Solar photon methods

Solar radiation respresents an inexhaustible, renewable energy source which can cover all global energy demands for all future time. The energy continuously radiated towards the earth is $1.7 \cdot 10^{17}$ W, i.e. 1.353 kW/m^2 outside the atmospheric layer. Due to absorption during the passage through the atmosphere, only about 3/4 reaches the earth's surface. Another feature of solar energy is its diurnal nature which means that at the latitude of

Sweden only about 1/3 of the incoming radiation on average over the year can be utilized for energy conversion purposes. Capital costs for solar power stations will thus be effectively trebled. The average solar power over the surface of Sweden is about 0.1 kW/m^2.

The wavelength range of solar radiation at the earth's surface is 300 - 1300 nm. All of the ultraviolet part of the spectrum below 300 nm is absorbed in the upper part of the atmosphere, mainly by ozone. Half of the energy is contained in the ultrared region of the spectra and half in the visible, 400 - 700 nm. Less than 8 % has wavelengths < 400 nm.

Solar radiation can be converted to useful energy carriers like hydrogen by photosynthetic biomass production (see 5.3.3.3), by direct thermal methods and by photon-based processes. Solar concentrators are necessary to reach the high temperatures required either for the direct splitting of water (see 5.3.1) or to obtain an acceptable efficiency in a Carnot heat engine.

In the latter case electricity is produced, which can be used for the electrolytic disintegration of water. The most costly item in such a plant is the solar electricity production device (mirrors, heliostats, receiver, turbo-alternator). Investments have been estimated at 1250 - 1500 $/kW(el), which must be capitalized during only 1/3 of the year. Using a real interest of 4 %, a depreciation time of 10 years, and additional running costs of 10 % of the capital charges, this gives an electricity price of approximately 6 - 7 c/kWh, which should be compared to the electricity cost according to our fuel price scenario (Table 5-20) of 4.4 c/kWh in 2025. Even assuming a 100 % efficiency of the electrolytic process and the same percentage of annual utilization (electricity from other sources is used during the other 2/3 of the year), the hydrogen production cost of 80 - 95 cr/GJ, obtained from data in Table 5-7, (14), is non-competitive by comparison with other production methods.

The heat supply required to split water in the liquid state to hydrogen and oxygen is 0.285 MJ/mole, which is equivalent to a radiation wavelength of about 420 nm. Only about 8 % of the solar radiation is below this level. However, photon absorption always occurs as a series of one-photon processes, and such a process cannot be used for the direct splitting of water according to

$$H_2O \rightarrow H_2 + \frac{1}{2} O_2$$

The lowest energy requirements for a one-photon reaction which splits water are obtained when the OH band is broken, which occurs for wavelengths < 246 nm in the ground state and < 178 nm in the first excited state. As has been noted, such short solar wave lengths do not reach the biosphere. In order to overcome the problem, research and development work has been directed to the study of ways of circumventing the energy restriction in single and multi-step processes, either by directly applying or imitating the general philosophy behind the natural photosynthetic reaction sequence, which is an 8-photon process, or by generating an electric current which is used for the electrolytic splitting of water. Multi-step processes have the advantage of a potential use of the full ground-level solar spectrum, while single-step processes require efficient utilization of the energetic part of the spectrum and the prevention of recombination reactions. Up to now the conversion efficiences achieved have generally been low, and serious fundamental or technical obstacles to their application on a large scale have arisen. The methods studied can be grouped into the following categories:

- Photovoltaic electrolysis
- Heterogeneous photo-redox methods
- Homogeneous photo-redox methods
- Bioconversion

5.3.5.1 Photovoltaic electrolysis

The generation of electricity by means of solar cells is a well known technique, for example in space research to charge batteries for remote devices. Light quanta act to eject electrons from a photosensitive semi-conductor, thereby leaving a positive potential and generating a negative one in an adjoining conducting metal, Figure 5-16. A cell potential of less than one volt is obtained. The cells must therefore be placed in series to generate the voltage needed to split water.

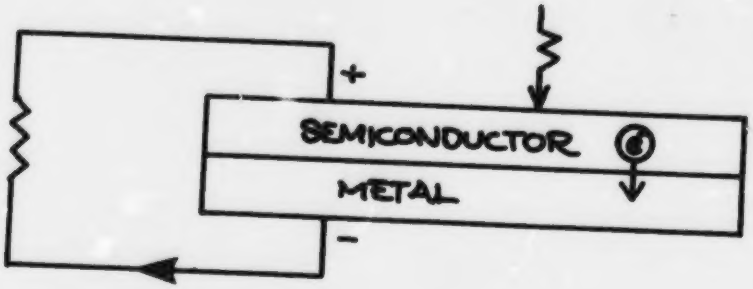

Figure 5-16

Photovoltaic device.

Suitable semi-conductors are either of the binary type, e.g. GaAs, CdTe and CdS, with conversion efficiencies between 10 and 20 %, or of the single chemical element type. Of these, silicon devices are the most commonly used type and have been commercially available for more than 20 years. They have efficiencies in the range 10 - 18 % and yield a peak power of 135 W/m^2 at 10 % efficiency.

The principal obstacle to the adoption of solar cells in large scale electricity production is their present high costs, 1500 - 10000 \$/m^2. However, there are promising new, low-cost manufacturing techniques which have recently been demonstrated for both silicon-crystal and GaAs technology. It is anticipated that the price might be reduced to about 100 \$/m^2 at the end of the century, together with an efficiency of 20 %.

If we use the values given above as possible costs in the years 1985 and 2005, the cost evaluation for electricity production summarized in Table 5-13 is obtained (annuity 12.33 %). With present-day techniques, solar cells appear to be completely non-competitive. If the rather propitious solar cell data assumed for 2025 prove to be correct, with electricity being produced at a cost of about 4.7 c/kWh, photovoltaic hydrogen production would become almost competitive with other methods discussed.

The cost of electricity according to our price scenario (Table 5-22) is 3.19 and 4.42 c/kWh for the years 2005 and 2025, respectively.

Table 5-13

Photovoltaic electricity production costs (US$).

	1985	2025
Solar cell, cost $\$/m^2$	1500	100
efficiency %	10	20
power W/m^2	100	200
Capital investment,		
solar cell $/kW(el)	15000	500
other equipment "	400	300
Annual average load h/day	5	6
Electricity c/kWh		
capital cost	104	4.50
operation cost	1	0.20
total	105	4.70

5.3.5.2 Heterogeneous photo-redox methods

A photo-electrochemical cell converts optical energy by means of reactions at semi-conductor surfaces. In a model like that of Figure 5-17, radiation produces electron/hole pairs of sufficient energy to produce oxygen evolution on an n-type semi-conductor, while hydrogen evolves externally at the surface of a metal such as platinum. Critical semi-conductor parameters are the band-gap and the achievable flat-band potential.

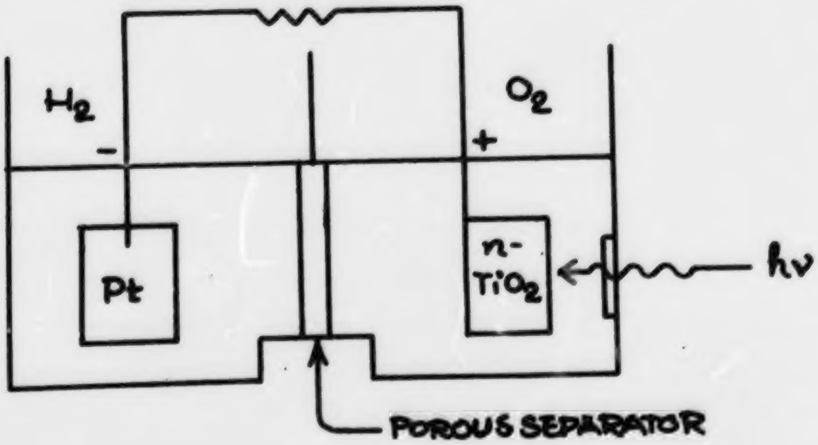

Figure 5-17

Photo-electrochemical cell.

Semi-conductors of the n-type like TiO_2, SnO_2 and ZrO_2 have large band-gaps between 3 and 5 eV, equivalent to radiation wave lengths of 415 - 250 nm, and potentials at equilibrium which are usually stable to electrode decomposition. Semi-conductors of the p-type like GaP, GaAs and Si have band-gaps between 1 and 2.3 eV and can thus more efficiently utilize the energy of the solar spectrum, but they are more liable to decomposition and usually require large external bias voltages.

Most research work has been expended on the TiO_2 system in which the major reactions are:

$$n - TiO_2 \xrightarrow{hv} 2e^- + 2p^+$$

$$2p^+ + H_2O \xrightarrow{TiO_2} \tfrac{1}{2} O_2 + 2H^+$$

$$2e^- + 2H^+ \xrightarrow{Pt} H_2$$

The process occurs for wavelengths < 415 nm with quantum efficiencies of about 0.1. The overall efficiency is only about 0.8 % since less than 8 % of the solar radiation lies below 415 nm. The electrode can be sensitized to visible light by adding a surface layer of a dye like alizarin or rose bengal. However, the dyes are rather unstable and reduce the intensity of incident light.

At present, it is very difficult to predict the future of the photo-electrochemical approach to hydrogen production. However, the method can hardly be expected to be developed for full-scale production within the time period of this study.

5.3.5.3 Homogeneous photo-redox methods

These methods can be regarded as photo-catalytic processes which use an approach with similarities to the natural photosynthetic reaction mechanism. Water solutions containing chemicals capable of absorbing solar radiation and transferring it to water for photolysis are irradiated. This may require one, two or multi-step photon transfers and/or reactions. The evolved product gases, hydrogen and oxygen, may be obtained separated or as a mixture, in the latter case requiring a second separation step.

Organic systems like dyes are generally considered too susceptible to decomposition. Efforts centre instead on inorganic systems, where the added chemical acts as a catalyzer in a double redox reaction. The Ce^{3+}/Ce^{4+} couple can be regarded as typical for such a process. In the first photon reaction, the 3-valent ions are oxidized with the liberation of hydrogen, and thereafter reduced to the original state in a second photon reaction under the liberation of oxygen. Unfortunately, the reaction sequence only occurs at wavelengths < 250 nm, i.e. not occurring in the biosphere solar spectrum.

Efforts are at present under way to develop systems that absorb in the visible range of the spectrum. The most promising results have been obtained with binuclear complexes in multi-step reactions, e.g. transfer reactions between the Ru-complex of bipyridine and the Fe^{2+}/Fe^{3+} couple in the presence of various uncharged sensitizing agents. It is difficult to foresee any economical applications of the current fundamental research within the surveyable future.

5.3.5.4 Bioconversion

A few photosynthetic bacteria and unicellular algae can produce hydrogen photochemically under the action of enzymes, such as hydrogenase and nitrogenase. Hydrogen is also produced together with light hydrocarbons by a number of anaerobic microorganisms during the anaerobic fermentation of carbohydrates. In the latter case, the hydrogen donor is of organic nature while in the first case this is still open to debate. However, indirectly the hydrogen originates from water.

Basically, solar radiation is absorbed by some form of chlorofyll pigment and transmitted to an electron in a donor compound through the chlorofyll centre. A sequence of reactions similar to the photosynthetic pathway occurs which ends in the liberation of hydrogen. Oxygen inhibits hydrogen production by inactiviting the major catalysts, hydrogenase and/or nitrogenase. It has recently been shown that some blue-green algae are not subject to oxygen inhibition. Studies are also going on to find oxygen insensitive forms of the enzymes. Photosynthetic bacteria that contain nitrogenase, an enzyme for fixing nitrogen, can only produce hydrogen in the absence of nitrogen.

The possibilities of using marine photosynthetic microorganisms in mass culture as a protein source or for the production of hydrogen is being studied in many places. Tropical and subtropical salt water environments are particularly favourable since they abound in many nutrients essential to the growth of photosynthetic organisms and have a high percentage of yearly sunshine. It has been shown in laboratory tests that the blue-green algae can produce about 0.3 ml of hydrogen gas per ml reaction mixture and 24-hour irradiation period (29). In order to achieve the annual production capacity of our large reference plant, 0.14 Mton, a one meter deep layer of an algae mixture would be required in an artificial or natural circular lake with a radius of about 3.7 km (area $\sim 4.3\cdot10^7$ m^2). It would also be necessary to arrange for the continuous separation of hydrogen from large volumes of air by suitable methods. From a technical point of view, such a project appears to be Utopian, even if economic calculations give reasonable cost estimates.

5.3.6 High energy radiation

The energy necessary to split one mole of water to hydrogen and oxygen, 283 kJ, is equivalent to 2.95 eV per molecule. High energy radiation > 100 keV, whether particulate or electromagnetic, carries sufficient energy to split more than 34000 molecules and to break about 20000 OH-bonds in water. However, depending on the type of irradiated matter and radiation, varying fractions of the available energy are actually absorbed by water molecules, and in addition recombinations and deactivation occur, competitive reactions with other substances present reduce the yield etc. Experimentally, yields have been observed of 1.75 splits/100 eV for fission fragments in water and 6 splits/100 eV for alpha particles in steam.

The primary reaction when ionizing radiation interacts with water is the formation of excited or ionized water molecules, free radicals and secondary rapid electrons:

$$H_2O \rightsquigarrow \begin{array}{l} H_2O^* \rightarrow H + OH \\ H_2O^+ + e_s^- \end{array}$$

The secondary electrons are successively thermalized to new radical species, hydrated electrons e_{aq}^-, under reactions with new water molecules. The radicals and ions formed undergo a sequence of further reactions to form various final products, which depend on the pH, water purity, temperature, radiation, oxygen content and dose rate. The overall reaction can be written as:

$$H_2 \rightsquigarrow H,\ OH,\ e_{aq}^-,\ H_2,\ H_2O_2,\ OH^-,\ H^+$$

The G value for the formation of molecular hydrogen in pure water at neutral pH, i.e. the number of molecules formed per 100 eV absorbed, is 0.45. With the addition of a hydrogen donor, the yield can be substantially enhanced (2.4 for formic acid), but this is counteracted by the extra energy consumption required to produce the donor substance. A G value of 0.45 means that about 96 MJ of radiation energy are required to produce 1 Nm^3H_2, i.e. an energy efficiency of 13.3 %.

Suitable sources for large scale production of hydrogen as the principal product or as a by-product by radiolysis are:

- Fission reactors
- Fusion reactors
- Electron accelerators
- Irradiated fuel elements and special long-lived radionuclides

It has been suggested that future fusion reactors might make available photons from leakage plasma or high energy neutrons which could be used to dissociate water on a large scale. A rough calcuation has shown that a dual reactor for both direct and indirect hydrogen production, the latter by conversion of simultaneously generated electricity to hydrogen by electrolysis, could produce hydrogen at an energy efficiency of about 42 %. Another idea which has been proposed is that aluminium should be added to a plasma torch, thereby generating U.V. light in the region 180 - 195 nm. Such wave lengths are well absorbed by water and can be used efficiently to dissociate water photolytically. However, for this market study it is assumed that fusion reactors will not be applied commercially before the year 2025, so that they will not be available for hydrogen production.

5.3.6.1 Fission reactors

Heterogeneous power reactors of the normal pressurized or boiling water type are not well suited for direct hydrogen production, either as a by-product or as the main product. For safety reasons, hydrogen evolution is instead always suppressed by the addition of suitable chemicals. Further, fuel element configurations favourable for chemonuclear processes are not consistent with those of todays' power reactors, which require the fission products to be firmly contained within the fuel particles. On the other hand, an efficient chemonuclear process, e.g. hydrogen production by water splitting, needs a thin, high surface area fuel structure through which the chemical reactants could pass to be exposed to fission-fragment tracks. It is not technically feasible to avoid the simultaneous contamination of the product stream by radionuclides. If only the escaping neutrons and hard gamma radiation outside the reactor core are utilized, this will lead to a low production capacity and conversion efficiency. A chemonuclear reaction which is particularly suitable for gaseous reactors is the radiolysis of CO_2:

$$CO_2 \rightarrow CO + \frac{1}{2} O_2$$

In a second step, separated CO is reacted with steam in a shift reaction to produce H_2 and regenerate CO_2. The process has the advantage of generating H_2 and O_2 in separate steps, thus avoiding the general problems in radiolysis processes of separating the two product gases. The expected G value and efficiency for the radiolytic reaction are 10 and < 30 %, respectively. With an efficiency of 90 % for the shift reaction, the maximum hydrogen yield that can be achieved is < 8 %. The annual production capacity in a 3000 MW(th) reactor with a load of 0.8 would be about 0.04 Mton H_2, compared with 0.14 Mton for our reference electrolytic plant. If the nuclear reactor is used for the simultaneous production of electricity, it seems probable that hydrogen might be produced at a cost which is competitive with that of the coal gasification method.

The homogeneous reactor concept has several inherent properties which appear to favour its adaption to hydrogen production. The fissile core material is dissolved or suspended in an acid water solution and is partly circulated to a small purification facility where all the gaseous fission products are continuously separated. Almost all of the fission and radiation energy is given off in collisions with water molecules. Due to the high LET effect of the fission fragments, the G value for hydrogen formation is ≥ 1.6. However, homogeneous reactors have never been run in large-scale application, and their relative costs can be expected to be higher than those of the commercial heterogeneous reactors of today. Using the same calculation parameters as for the chemonuclear concept above, a large hydrogen production plant could reach an annual capacity of 0.025 Mton and achieve an energy conversion efficiency of about 4.7 %. In dual purpose applications (electricity-hydrogen), the hydrogen cost might be fully competitive with other production methods, since the extra costs for separating and purifying the hydrogen product in the off-gas stream can be expected to be relatively small.

5.3.6.2 Electron accelerators

Electron accelerators are well suited for the industrial irradiation of liquid or gaseous phases, but the electron beam has only a very short range in condensed media. The equipment is usually installed in a concrete cell of limited dimension and wall thickness. The radiation level in working areas outside the cell can be kept low because of the small area of the directed beam. The present generation of commercially available accelerators has a maximum beam power of 150 kW. Much higher powers are needed for the large-scale production of hydrogen.

An estimation has recently been made of the power efficiency and cost of a 35 MW accelerator for smoke gas irradiation (30). Using these figures and assuming that the irradiated medium is water steam gives the following completely non-competitive production data:

Annual production capacity	70 ton hydrogen
Energy efficiency	< 0.6 %
Hydrogen cost	ca 10000 cr/GJ

5.3.6.3 Gamma cells

Large commercial gamma cells most commonly use artificially produced Co60 or the long-lived fission product Cs137 as radiation sources. Irradiated reactor fuel elements can also be used for this purpose but their radiation energy is less homogeneous and varies with time. According to experience, the total irradiation costs also become somewhat higher.

A rough calculation shows that the cost is completely prohibitive. Even assuming that very large activities of e.g. Cs137 would be available at a price as low as 1 cr/Ci, the costs for hydrogen production would be of the order of 10^5 cr/GJ.

5.3.7 Special production methods

In a recent publication (31), it has been proposed that basaltic magmas could be used for water splitting. Chemically, the lava contains about 10 % ferrooxides. If steam is injected through a bore hole into the geothermal resource at the prevailing temperature, 600 - 1300°C, hydrogen concentrations of about 1 to 3 mole percents are predicted in the return pipe. The yield can be further increased by the addition of biomass. Experimental work with lava has confirmed the predictions. Approximately 2 Mton of hydrogen could be produced from 180 Mton water and 1 cubic kilometer of basaltic lava. Obviously, considerable engineering problems remain to be overcome.

According to another proposal (32), very intense magnetic fields of the order of 10^4 Tesla can by their interaction with para-magnetic oxygen molecules lead to a displacement of the dissociation equilibrium for water. Temperatures less than 600 K are sufficient to give efficiencies near to those of a Carnot process.

5.3.8 Liquefaction of hydrogen

The liquefaction of hydrogen is a complicated exercise in cryogenic engineering. There are very few commercial-scale plants in operation today. The largest are connected to the US NASA-program and have outputs of 60 tons LH_2 per day, while the largest European plants can be regarded as large pilot plants with capacities of less than 2 tons per day.

To liquefy hydrogen, energy must be withdrawn from the gas to condense it. This is more complicated than for other gases for the following reasons:

- The low boiling point of hydrogen, 20.27 K in the para state.
- The ortho state content of GH_2 at normal temperature, 75 %, is spontaneously and successively converted to pure para state at the boiling point under the liberation of 725 kJ/kg, which is higher than the heat of vapourization, 448 kJ/kg. To avoid LH_2 losses due to evaporation, catalysts are incorporated in the liquefier plant to accelerate conversion to the para state.

- The Joule-Thompson coefficient for hydrogen is negative at temperatures above 202 K which means that high-pressure gas will get warmer if allowed to expand at temperatures above this point. For this reason, the gas is precooled with liquid nitrogen before the final liquefaction process starts.

- The hydrogen gas must also be efficiently purified from impurities like H_2, CO_2, CH_4 and N_2 before final liquefaction.

Modern hydrogen liquefaction plants use a sequence of reciprocating compressors and precooling steps for both H_2 and the precooler N_2 before the temperature decrease below 202 K is started by means of an expansion engine using porous expansion valves of the Joule-Thompson type. The working pressure is usually around 3 MPa.

In technical journals, figures varying between 10.9 and 12.0 MJ/kg are reported for the theoretical work, excluding the ortho→para conversion, in order to liquefy hydrogen. Due to fairly high losses, mainly sustained in compressors, turbines and heat exchangers, the practically achievable efficiency figures for large industrial facilities are between 35 and 45 MJ/kg. An actual work of 40 MJ/kg will be used in the following cost calculations, i.e. a process efficiency percentage of 72 % in relation to the product energy content (142.5 MJ/kg).

Cost calculations for a plant with a daily production capacity of 400 tons, i.e. about the same capacity as our reference plant, are summarized in Table 5-14. The ordinary economic rules of this study have been adopted, i.e. a real interest of 4 % and a depreciation time of 10 years.

Table 5-14

Large-scale production costs of LH_2.

	1978	1985	2005	2025
Investment cr/GJ/year		12.8	12.8	12.8
Electric energy cr/GJ	24.4	28	39	54
LH_2 costs cr/kg				
capital	0.25	0.25	0.25	0.25
energy	0.98	1.12	1.56	2.16
operation	0.10	0.11	0.13	0.15
total	1.33	1.48	1.94	2.56
Total costs cr/GJ	9.35	10.4	13.6	18.0

5.3.9 By-products

Oxygen gas is always intermittently or finally evolved when hydrogen is produced with water as raw material. In electrolysis, it is obtained as a highly pure gas in a separate product stream. Thermochemical closed systems are also intended to produce oxygen in a pure form in a separate output stream. In the open systems, the oxygen gas evolved is generally consumed in one or more combustion steps. With a few exceptions, oxygen would be obtained together with the hydrogen product in biochemical or radiation methods.

Large amounts of oxygen are already being consumed by the iron and steel industry (about 0.5 Mtons per year in Sweden), and the consumption can be expected to increase by at least another order of magnitude within the next 50 years (Chapter 9). Market sectors which are slowly gaining importance are the treatment of community sewage and the clean-up of lake and river waters by the destruction of organic pollutants. If incinerators were fed with pure oxygen instead of air, there would be a higher flame temperature. The trash would burn more efficiently, CO would be eliminated and smog formation reduced. Nitrogen oxides would be completely eliminated as a pollutant if internal combustion engines were run on hydrogen-oxygen mixtures.

Large amounts of oxygen would be available as a consequence of a hydrogen economy. The annual production capacity of a large electrolysis plant of the reference size is about 1.1 Mton. It is today very difficult to assign a special credit value to the oxygen by-product. The value is strongly dependent on transportation distances. Piping is only regarded as economical for distances shorter than 100 km because of the competitiveness of oxygen extracted from air. The average value assigned today to oxygen consumed in the Swedish steel industry is 175 cr/ton, i.e. a hydrogen credit of about 10 cr/GJ.. A suitable credit value according to American reports is 3.5 ± 1.0 cr/GJ. In this study, a credit equal to zero is given to all by-products.

Heavy water can be obtained as a by-product when water is electrolyzed. The process has been applied in Norway since the late forties. According to a recent Canadian proposition (33), high-purity D_2O can be obtained in a combined electrolysis-catalytic H_2/H_2O exchange process. The water becomes enriched in deuterium as it passes down a catalyst bed. The product yield has been estimated to be about 70 % of the original deuterium content in the water. With the present D_2O price of 215 $/kg, a net hydrogen credit of about 4 cr/GJ is obtained. The annual production capacity of our large reference plant would be c. 100 tons of heavy water.

5.4 Alternative energy carriers

According to the three energy scenarios of this study, competing energy carriers are in the first place electricity, natural and synthetic petrol and gas, and methanol. Costs of petrol, jet fuel and NG as well as the raw materials coal, coke and crude oil have been settled within the IEA common framework (Chapter 1), Table 1-1, and are implemented throughout the study. Together with costs for the other alternative energy carriers which are discussed below, they are summarized in Table 5-22 (1 $ = 4.40 cr). The figures given are production costs or free import costs to a Swedish port. Additional costs for transmission, distribution and large-scale storage are accounted for in Chapters 6 and 7.

5.4.1 Electricity

According to the energy scenarios, electricity will be mainly produced from domestic primary energy sources (nuclear fuel, wind and water power, biomass). Domestic costs are stated to be independent of the international fuel price escalation in the applied constant 1978 currency. However, it seems reasonable to assume that the electricity costs cannot be completely independent of the generally escalating international fuel prices. The same escalator factor as for the Swedish GNP, 1.6 % per year, has therefore been applied. This factor agrees well with the international cost escalator for coal. This is also what is to be expected, as coal will become the dominating world fuel resource during the period. The average Swedish production cost for electricity in 1978, 24.4 cr/GJ (2 c/kWh), is used as the calculation basis.

5.4.2 Synthetic natural gas

SNG is assumed to be mainly produced by coal gasification. From available American and German data, the average import price in 1985 is estimated to be 15.7 cr/GJ. This cost is assumed to increase at the same rate as that of coal.

5.4.3 Synthetic petrol

Various processes can be used for the production of synthetic petrol. A recent Swedish study (34) discusses production costs for the Mobil process, which converts methanol catalytically to high-octane petrol with a very high yield. The reaction is performed in a gas phase at a temperature of 300 - 400°C and at a pressure of 0.2 - 2.5 MPa. The catalyst is of the zeolite type and has form-selective properties. The process is said to be both technically and economically superior to the Bergius and the Fischer-Tropsch methods.

Cost calculations for the Mobil process are summarized in Table 5-15 for a plant with an annual capacity of 0.2 Mton petrol and a thermal efficiency of 84 %. The methanol price is set at the import price of Table 5-22.

Table 5-15

Large-scale production costs of synthetic petrol (the Mobil process).

	1978	1985	2005	2025
Investment costs Mcr	55	55	55	55
Methanol price cr/ton	602	656	878	1068
Petrol costs cr/ton				
capital	34	34	34	34
raw material	1565	1705	2282	2780
operation	88	89	92	96
total	1687	1882	2408	2910
Total costs cr/GJ	35.1	38.1	50.2	60.6

The costs obtained have been compared to direct cost figures given in (34) as well as to rough calculations for coal gasification processes. The agreement is surprisingly good. A slightly corrected value is adopted in Table 5-22.

5.4.4 Methanol

Methanol is produced commercially by methods which are similar to those which are now in use or being developed for the production of hydrogen with coal, NG and biomass as the raw materials (see 5.3.3)

5.4.4.1 From coal and renewable organic feedstocks

The technology involves three distinct steps: gasification, gas stream modification and catalytic methanol synthesis (35). The gasification step converts the solid material into a gas mixture through heating and addition of other gases, such as oxygen, air or steam. The heat necessary for the reaction is provided by the feedstock. Many commercial processes exist for the gasification of coal. Three main types of reactors are in use: moving bed, fluidized bed and entrained flow (c.f. 5.3.3.2). For biomass, peat and organic wastes, there is a lack of experience of full-scale processes. However, several of the processes used for coal can after modifications become applicable to biomass of different kinds. The fluidized bed technique, e.g. the Winkler gasifier, with oxygen as the oxidation medium seems today to be the most promising for biomass and peat. Air processing as well as separate burning and gasifying compartments might later become more technically and economically feasible (36).

The gas modification step involves the preparation of the exact proportions of CO, H_2 and CO_2 needed for the methanol synthesis, removal of impurities and syngas compression. As a rule, the hydrogen content is too low; this can be corrected by the shift reaction or by the addition of merchant hydrogen. The purification includes for example the complete removal of all sulphur compounds, because they poison the catalysts of the final synthesis process.

The methanol synthesis is performed by well established processes which involve specific catalysts and process requirements. The overall reactions are:

$$CO + 2H_2 \rightarrow CH_3OH$$

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O$$

Operating conditions are pressures in the range 4 - 30 MPa and temperatures of 220 - 280°C. Reactor design and recycle flows vary from process to process. At present low-pressure processes give the lowest investment and operational costs. Feedstock requirements are an H_2/CO ratio of 2:1, small amounts of CO_2 (< 0.2 %) and about 1 % inerts. Thermal efficiencies vary between 38 - 55 % (37).

5.4.4.2 From NG or light hydrocarbons

The primary reaction, which is a steam reforming reaction between a gaseous hydrocarbon and water, is carried out between 1300 and 1400°C and yields a mixture of mainly CO and H_2:

$$CH_4 + H_2O \rightarrow CO + 3H_2$$

$$CH_4 + 2H_2O \rightarrow CO_2 + 4H_2$$

Both reactions are strongly endothermic. The necessary heat is obtained by the combustion of gas with air. The proper composition of the syngas for methanol production is adjusted in the same way as discussed above.

5.4.4.3 From carbon dioxide

CO_2 is a by-product of the calcination of limestone and dolomite. The product gas can contain up to 40 % CO_2 (38). After a purification step, CO_2 is reacted catalytically with independently produced H_2 to synthesize methanol in a single endothermic stage:

$$3H_2 + CO_2 \rightarrow CH_3OH + H_2O$$

5.4.4.4 Economic considerations

Cost calculations for various production methods have recently been made by a Swedish development company, using a daily production scale of 2000 ton methanol and a load factor of 0.9 (39). The figures are summarized in Table 5-16 after being converted to the economic rules of this study. As is apparent from the table, the IEA price scenario, Table 2-1, deviates strongly and has therefore not been applied for further calculations and discussions.

Table 5-16

Methanol production costs.

Feedstock Year	NG			Coal			Biomass			IEA price scen.		
	1985	2005	2025	1985	2005	2025	1985	2005	2025	1985	2005	2025
Investment, Mcr	567	567	567	1264	1264	1264	1370	1370	1370			
Overall thermal efficiency, %	62	62	62	55	55	55	46	46	46			
Feedstock cost, cr/ton	662	1270	2115	194	320	424	257	272	290			
Methanol cost, cr/ton												
capital	98	98	98	220	220	220	238	238	238			
feedstock	438	841	1400	276	413	603	745	790	839			
operation	120	120	120	245	245	245	275	275	275			
total	656	1059	1618	741	878	1068	1258	1303	1352			
Methanol cost, cr/GJ	29.0	46.7	71.3	32.6	38.7	47	55.4	57.5	59.6	30.0	56.3	93.7

5.4.5 Wood, biomass and peat

Biomass products and peat are primary energy sources. Only in heating applications are they alternatives to hydrogen. Their production costs given in Table 5-22 are pure cut and collecting costs. In all applications, transportation costs must be added, and as might be expected for bulky products like biomass and peat, these are strongly dependent on freight distance. The figures given in Table 5-17 are average transport costs for distances < 50 km. Transports over longer distances are usually non-economical.

Table 5-17

Average transport costs for distances < 50 km in cr/GJ.

	1978	1985	2005	2025
Wood	3.7	3.8	4.0	4.5
Biomass	3.5	3.6	3.8	4.0
Peat	3.5	3.6	3.8	4.0

5.5 General production considerations

Present Swedish requirements for secondary energy carriers are covered to nearly 100 % by the import of raw or refined oil products. By 1980 this import can be expected to encumber our foreign trade balance with more than 30 Gcr. The agreed policy of the government and the parliament is to try to reduce this deficit by every possible means. A natural assumption in this market study has therefore been that any future large-scale production of hydrogen should be carried out domestically and should use water as the raw material.

Such a policy would decrease our foreign trade deficit and make us more self-supporting in energy. Water of the required purity is abundantly available in most parts of Sweden; apart from heat and/or electricity, it is the only raw material or energy source which is needed in large quantities for those direct water splitting methods that can be regarded as realistic alternatives within the period studied, i.e. electrolysis, direct thermal splitting and closed thermochemical cycles. The production of hydrogen with a suitable mixture of biomass (peat) and water as the raw materials must also be regarded as a serious, domestic manufacturing alternative. According to the energy scenarios of this study, the heat and/or electricity required for the processes are also obtained from domestic primary energy sources, i.e. nuclear, wind and water power, biomass and possibly solar energy.

The policy discussed above rules out the present dominating manufacturing methods, i.e. steam reforming or partial oxidation of hydrocarbon compounds and coal gasification, as future domestic production possibilities.

The market analysis has shown that fairly significant demands for hydrogen may be expected already in 2005. The only process which conforms with general policy and is likely to be available at that time for full-scale industrial adaptation is electrolysis. A plant of SPE type and of our reference size (0.14 Mton H_2 per year) would have the general data summarized in Table 5-18. The over-all energy efficiency is assumed to be 86 %.

Table 5-18

Production and requirement data for an H_2-plant with an annual capacity of 0.14 Mton in 2005; SPE-electrolysis

Annual H_2 production	Nm^3	$1.56 \cdot 10^9$
Annual H_2 production	PJ	20
Annual O_2 production	Mton	11.2
Annual H_2O requirement	Mton	ca 13
Electric input	PJ	23.5
Investment capital	Mcr	750

5.5.1 Product purity

Commercial electrolytic processes are easily adapted to give hydrogen as well as oxygen purities > 99.95 %. Such a high purity is usually neither necessary nor desirable in most large-scale applications of hydrogen as an energy carrier. Because of safety reasons, further discussed in Chapter 14, an odoriferous and/or visible product with a purity of about 99 % is the preferred commercial object.

Direct thermal water splitting gives a product mixture of H_2 and O_2 which necessitates a second separation step. At present it is not known what purities can be achieved while keeping the yields high and the costs competitive. Closed thermochemical cycles generate H_2 and O_2 in separate steps. If these are electrolytic, the product gas will most probably be obtained with a high purity. On the other hand, chemical final steps can be expected to generate contaminated products which require further purification.

Present commercial processes for hydrogen production with coal or hydrocarbonaceous compounds as the raw material gives a product with a purity of between 95 and 98 %. This is not sufficient for certain potential applications, for example for the generation of electricity in hydrogen-charged fuel cells.

5.5.2 Choice of production site

The market investigation indicates a possible annual hydrogen demand of 13 - 119 PJ in 2005 and 20 - 250 PJ in 2025, which can be covered by up to 6 and up to 13 large plants of the reference size, respectively. The lower limit definitely eliminates the introduction of large hydrogen production facilities in Sweden. The higher limit will be achieved if plant construction is started in 1995, and if a new plant is taken into operation about every second year.

Plant sites must have an abundant supply of pure or easily purified water. They should further preferably be situated in the near vicinity of a high voltage network and also of an existing or a planned main gas-piping system. The principal potential customer according to the market analysis is the transport sector, which necessitates a flexible, continuous, highly branched and rapid distribution system. A system for supplying liquid hydrogen by rail or road is unlikely to be a satisfactory option. On the other hand, there is no necessity for near access to harbour facilities for the transport of heavy loads, since all the raw materials are available at the site.

A large production plant of the reference size must have near access to storage locations. It has been assumed that a storage volume of 1/10 of the annual production capacity, i.e. c. $1.5 \cdot 10^8$ Nm^3H_2 (1.5 Mm^3 at 10 MPa), would be reasonable. As is discussed in Chapter 6, underground storage either in geological aquifers or in unlined, uninsulated rock caverns provides the best alternatives. The former only exists in certain parts of Sweden, for example in Skåne, while underground rocks of satisfactory quality are available all over the country.

Bearing in mind the facts discussed above, sites for the maximum of 13 plants ought to be chosen in areas with a large share of the population and close to the main gas-piping system. Skåne is one such region, with the added advantage of cheap storage space. Other regions are in the neighbourhood of the towns of Stockholm, Örebro, Gothenburg and Sundsvall. The market analysis has not identified any large industrial consumer with a demand of the magnitude of the reference plant, except in the case of a potential future large-scale production of methanol or ammonia. In this case, a plant combined with H_2 production would be a natural choice. The marketing of the by-product oxygen, which tolerates only fairly short transport distances (see 5.3.9), is another aspect which should be taken into consideration. The iron and steel industry is a potential customer for large quantities of both oxygen and hydrogen, Chapter 9.

If hydrogen is to be applied in a special small sector, concentrated to one place or introduced at an earlier time, it might be advantageous to construct a small plant solely for this purpose. This would be the case for international flights where LH_2 is the only acceptable hydrogen form.

5.5.3 Scenario differences

Scenario A is a nuclear scenario with electricity available in large amounts. The preferred production method for hydrogen is likely to be electrolysis, using the SPE process during the introductory period and turning to more advanced processes like oxide electrolysis at the end of the period. Direct thermal or thermochemical water splitting with nuclear reactors as main sources are other possible alternatives, if they are sufficiently developed technically and also become economically competitive.

Scenario B is a scenario for renewable energy sources. Electricity is mainly used within industry, but with great restrictivity. Electrolytic hydrogen production is thus conceivable, but a more probable course of development is the use of biomass methods or, at the end of the period, solar-driven direct thermal or thermochemical processes. Methanol, produced from biomass, is the main competitor in the dominating application sector, namely transport.

Scenario C allows the free import of synthetic NG and petrol, which implies severe competition for hydrogen in most potential applications, Table 5-22. The introduction of domestic large-scale production of hydrogen might therefore require to be promoted by special governmental actions. Electrolysis would then be the likely production method.

5.6 Safety and environmental aspects

The significant hazards associated with the large-scale handling of hydrogen include its low ignition energy, wide fire and explosion limits and a great tendency to leakage. Further, the gas is colourless and odourless and can not be detected by human senses. These hazards are partly counteracted by the rapid dispersion of hydrogen leaks and spills because of its buoyancy and high rate of diffusion. Added hazards associated with LH_2, which are, however, less likely to be encountered in the probable Swedish production philosophy, are physiological damage due to freezing burns and frost bites and the formation of explosive slurries with air. These problems are discussed in more detail in Chapter 14.

Safety precautions must be taken at all stages of the manufacturing process where a leakage risk exists. They comprise for example the elimination of likely ignition sources, the installation of sensitive monitors to rapidly detect a leak of invisible gas, safety vents to avoid pressure build-up, and a continuous inspection of high-temperature and/or high-pressure equipment and pipelines for fractures or embrittled zones. Adequate ventilation as well as pressure differences between different operation areas should be maintained in order to limit the O_2 concentration to $< 25\ \%$ and to keep the H_2 concentration as low as possible. Experience from the large electrolysis plants in operation in Europe and India has shown that all safety problems can be overcome and that incidents can be limited to acceptable levels of occurence and extent.

From an environmental point of view, the production of hydrogen with water as the raw material is an extremely desirable industrial process. The only conceivable accidental releases in electrolysis, besides water, are gaseous H_2 and O_2 which are both completely physiologically unharmful. All the transportation and storage of raw material and product is done by underground pipelines and reservoirs and does not put a burden on ordinary transport systems or disturb the surrounding landscape. Accidental explosions are strongly localized to the explosion site and do not give rise to harmful products except for minor amounts of NO_x.

If an external heat source other than electricity is required for the production process, e.g. a nuclear reactor or biomass products, significant environmental implications would arise which are common in a modern energy producing and consuming society. By contrast with the combustion of oil and coal, the combustion of continuously regenerated biomass has the advantage that it does not increase the global CO_2 content.

Accidental releases or explosion incidents in closed thermochemical cycles of the type mentioned in 5.3.4 can result in very serious consequences for the environment, as many of the compounds recirculating in large amounts within the system are highly corrosive and poisonous.

5.7 Summary

After an introductory summary of the general properties of gaseous, liquid and solid hydrogen, a broad survey is given of those large-scale methods of producing hydrogen which are already commercially adapted, are under development for commercial application or have been proposed as potentially possible. The water splitting reaction serves as the main source of hydrogen, but in a few cases additional hydrogen is obtained from the heating medium, coal, biomass or hydrocarbonaceous compounds. Other primary or intermediary energy or heat sources conceived are nuclear and solar power and electricity.

Process patterns for the different production methods are given, advantages and disadvantages are discussed, capital investments and operating costs are calculated, and safety and environmental aspects are summarized. The results obtained are used to evaluate the potential possibilities for the domestic manufacture of hydrogen in a reference plant of an annual capacity of 0.14 Mtons H_2.

Conventional processes with coal and hydrocarbon compounds as raw material are disregarded because of the restrictions imposed in this study. Electrolysis is judged to be the most competitive domestic production method, initially using the SPE method and at the end of the period considered perhaps with higher temperatures and more advanced electrolyte systems such as solid oxides. Biomass conversion is preferable in scenario B with its restrictions on the use of electricity. According to rough estimates, such methods offer prospects of production costs similar to those for electrolysis. The commercial application of direct thermal or closed thermochemical water splitting appears more far-fetched but might be possible at the end of the period. Expected costs are of the same magnitude as those above.

Photochemical and photo-induced bioconversion methods are unlikely to be sufficiently developed before 2025 as they give rise to technical problems which are difficult to solve. However, their costs might be of comparable magnitude to those discussed earlier. The direct application of high energy radiation, from either nuclear reactors, gamma sources or particle accelerators, for water splitting is already technically feasible, but the hydrogen cost must always remain completely prohibitive.

Production methods and costs for alternative energy carriers, such as electricity, methanol and synthetic petrol, are also briefly surveyed.

Cost calculations for most of the hydrogen production methods discussed are compared in Tables 5-19 - 5-21. Cost data are taken from the earlier, more detailed presentations in this chapter, averaged in view of their reliability, and converted to the general economic rules of this study, i.e. the Swcr of 1978, an annual capacity factor of 90 %, a real interest of 4 % and a depreciation time of 10 years. The costs given in Table 5-21 can only be regarded as very rough estimates, since none of these new methods has been applied on a technical scale.

Table 5-19

Costs of producing hydrogen by conventional methods (US$ and Scr).

Production method	Steam reforming NG				Part. oxidation oil				Coal gasification*			
Year	1978	1985	2005	2025	1978	1985	2005	2025	1978	1985	2005	2025
Capital investment c/m^{3}H$_2$/year	6.09	6.09	6.09	6.09	15.75	15.75	15.75	15.75	23.37	18.50	18.50	18.50
Total energy efficiency %	75	75	75	75	65	65	70	70	60	64	64	64
Product costs c/m^3												
capital	0.75	0.75	0.75	0.75	1.94	1.94	1.94	1.94	2.88	2.29	2.29	2.29
feedstock	4.07	4.63	8.90	14.80	4.91	5.62	9.14	13.94	3.00	3.04	4.53	6.60
operation	0.31	0.31	0.31	0.31	0.90	0.90	0.90	0.90	1.45	1.15	1.15	1.15
total	5.13	5.69	9.96	15.86	7.75	8.46	11.98	16.78	7.33	6.48	7.97	10.04
Total costs cr/GJ	17.68	19.60	34.32	54.65	26.70	29.15	41.28	57.82	25.25	22.33	27.46	34.64

* Conventional Koppers-Totzek (K-T) 1978, an advanced K-T from 1985.

Table 5-20

Cost of producing hydrogen by electrolysis (US$ and Scr).

Production method Year	Advanced alkaline 1985	SPE 1985	SPE 2005	Advanced high temp. 2025
Capital investment				
$/kW$_{el}$	260	200	180	220
c/m^{3}H$_2$/year	14.10	10.46	9.41	10.10
Total energy efficiency %	82	86	86	97
Product costs c/m^3				
capital	1.74	1.29	1.1.3	1.24
electricity	9.84	9.48	13.11	15.94
operation	0.75	0.65	0.60	0.80
total	12.33	11.42	14.84	17.98
Total costs cr/GJ	42.48	39.35	51.13	61.95

Table 5-21

Cost of producing hydrogen by new, technically undeveloped methods.

Method	Year	Investment cost cr/Nm^3/year	Hydrogen cost cr/GJ
Direct thermal water splitting by solar concentrators	2025	1.8	c. 60
Electrolysis by solar concentrators	2025	3-3.6	80-95
Thermochemical methods*	2005		50-55
	2025	0.75-0.8	64-70
Photovoltaic (solar cells)	2025	c. 2	c. 70
Electron accelerator	2025		c. 10^4
Gamma cells	2025		c. 10^5
Biomass	1985	0.50	43
	2005	0.50	47
	2025	0.50	51

* Westinghouse or H_2SO_4 - HBr process.

The results obtained are collected in Table 5-22 together with costs for alternative energy carriers and primary energy sources determined in this chapter or given in the agreed fuel cost scenario of this study (Table 2-1).

Table 5-22

Fuel cost scenario (production).

Fuel	Heat content GJ/ton	Specific weight	Fuel costs cr/GJ			
			1978	1985	2005	2025
Power coal	29	0.88	6.20	6.70	10.0	14.6
Coke	31		13.6	14.8	22.1	32.2
Wood (dry)	19	0.40	15.8	16	17	18
Biomass (dry)	17	0.35	11.2	11.5	12.2	13
Peat (dry)	20	0.30	10	10.2	11	12
Crude oil	46	0.86	11.0	12.6	22.0	33.5
Natural gas	55.3	$0.69\cdot10^{-3}$	10.5	12.0	23.0	38.3
Synth. natural gas	55	$0.7\cdot10^{-3}$	14.2	15.7	23.5	34.0
Petrol	48	0.73	19.5	22.2	36.5	61.4
Synth. petrol	48	0.73	35	39	51	62
Jet fuel	47.5	0.76	21.1	24.1	39.6	66
Methanol (import)	22.7	0.79	26.5	30	43	52
Methanol (biomass)	22.7	0.79		55	58	60
Electricity			24.4	28	39	54
GH$_2$ (electrolysis)	142.5	$0.09\cdot10^{-3}$	54	42.5	51	62
GH$_2$ (biomass)	"	"		43	47	51
GH$_2$ (steam reforming)	"	"	17.7	19.6	34.3	54.5
GH$_2$ (coal gasification)	"	"	25.3	22.3	27.5	35
LH$_2$ (electrolysis)	"	0.07		52.9	64.6	80

Estimated investment costs for a large plant of the reference size are collected in Table 5-23 for realistic production methods. The market analysis shows that between 0 and 13 plants of this size are required during the period (1955 - 2025) to satisfy the calculated demand. Investment costs for the primary energy are not included in the figures.

Table 5-23

Investment costs for a GH_2 plant with an annual capacity of 0.14 Mtons.

Method	Investment costs Gcr
Steam reforming	420
Coal gasification	1270
Electrolysis (SPE)	650 - 700
Biomass gasification	780
Thermochemical closed cycles	1250

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6. LARGE-SCALE STORAGE

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6.1 Introduction

Even on a global scale, only an insignificantly small amount of all the hydrogen produced is at present stored for any length of time. Hydrogen is for the most part produced according to the needs of the manufacturer, and any surplus is either burnt off or sold to consumers in immediate neighbourhood.

The fact that hydrogen is consumed immediately after production reduces the need for storage, which is probably why the techniques for storage of hydrogen have not changed to any extent in the USA since an economical method of storing large quantities of liquid hydrogen was discovered. The situation in Europe is probably not much different. Exceptions which may be mentioned are the development of larger containers for liquid hydrogen in the context of space rockets, and an increase in storage pressure in gas containers up to 100 MPa. Another exception is a technique for the storage of hydrogen gas in solution-mined salt caverns, which has been developed by Imperial Chemical Industries (ICI) Ltd at their Teesside facility in England (1).

In a future energy system based principally on the utilization of hydrogen as an energy carrier, the demand for a continuous and reliable supply of energy will create the need for storage capacities which will be so large that current techniques will not be adequate. They will need to be developed or replaced by new untried methods in order that storage costs can be kept at a reasonable level. It is probably irrelevant whether the necessary energy for the production of hydrogen gas is produced in high temperature reactors, in hydropower plants or in solar energy plants.

There will be a need for storage capacity not only at production plants but also at the other end of the distribution network, in proximity to the consumers.

The need for storage arises when production and consumption are not immediately consecutive. Production can in principle be constant over the year, whereas consumption varies greatly with time. Heating demands cause considerable load peaks in winter, while the warmer part of the year and the industrial shut-down during the summer holiday period cause a slump in demand. On top of seasonal load variations there are also short-term changes in load during the day and during the week. These short-term load changes are, however, to a large extent equalized since the number of consumers is large and their consumption of energy varies in amount and with time.

The size of the individual storage unit will vary according to variations in the difference between production and consumption over the year, the month, the week and the day. The variation of this difference in time and size is in its turn dependent on the size and infrastructure of the area to be supplied, among other factors. The size required may also be influenced by safety and environmental demands made on the facility and by the introduction of interruptible supply.

It is naturally difficult to quantify Sweden's total future need for storage capacity, since this need will be influenced by conditions which cannot be predicted. An example is the question of which primary energy sources will predominate. If nuclear energy is used on a wide scale, the seasonal storage requirements will be of importance for the following reasons:

The overheads involved in the production of energy in nuclear power plants are high, which means the operation should be continuous over as large a part of the year as possible. Since consumption varies, the need for massive storage capacity arises.

If neither nuclear nor fossil fuels are used for energy production, solar energy will have to meet the major part of the demand for energy. However, even in this case storage will be of considerable importance, if solar energy plants are to be used for the production of hydrogen.

The total consumption of energy in Sweden is approximately 1.5×10^9 GJ per year. The following simple calculation is made in order to give some idea of the size of the storage problem.

The consumption of energy for house heating is assumed to amount to half the total energy demand and to be distributed over the whole year in proportion to the difference between 20°C and the monthly average temperature, which is assumed to be that of Stockholm. The rest of the energy consumption is assumed to be equally distributed over the year. If the production of energy is also assumed to be constant throughout the year, the storage capacity required is shown by the shaded area in Figure 6-1, representing an amount of energy equal to 0.18×10^9 GJ. The example is taken from (2).

The energy content of 1 m^3 of hydrogen gas is 12.77 MJ/m^3 at atmospheric pressure and a temperature of 0°C. In 1 m^3 of liquid hydrogen, it is 10.0 GJ. If hydrogen gas is stored at a pressure of 5 MPa and at 0°C, the volume required in the example above will be approximately 300 million m^3. The corresponding volume for liquid hydrogen will be approximately 18 million m^3.

Hydrogen is stored either as compressed gas or in liquid form at very low temperature. As far as Sweden is concerned, storage of hydrogen on a large scale could probably be carried out in the following ways:

- Underground, in gaseous form, in very large geologically formed reservoirs - "Geological storage".
- Underground, in gaseous or liquid form, in large rock caverns which are constructed for the purpose or which may be abandoned mines.
- Underground, in gaseous or liquid form, in large tanks situated in rock caverns.
- Above ground, as compressed gas or liquid in large, conventional tanks.

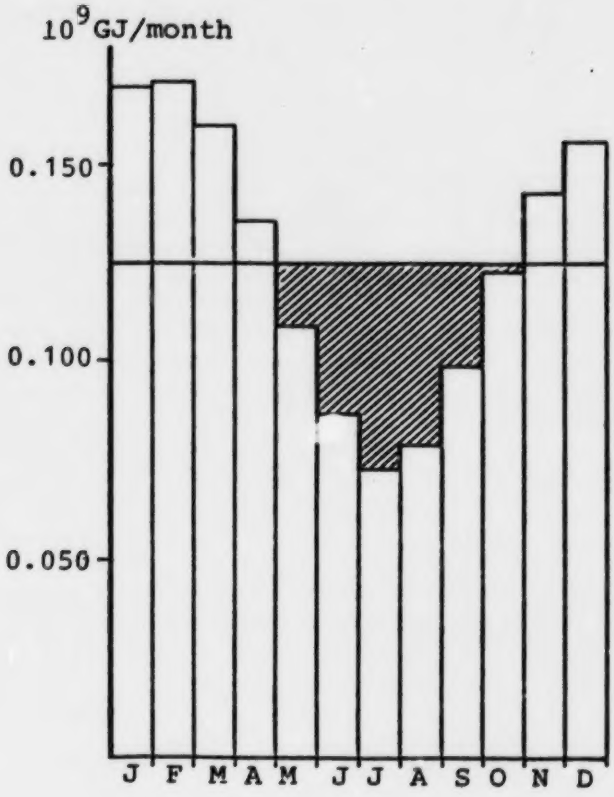


Figure 6-1

A numerical example relating to the seasonal requirements for storage of energy in a society with conditions for heating of building etc as of today and constant energy production (2).

6.2 Underground storage

6.2.1 General

The storage of hydrogen in a gaseous form can probably be carried out in the same way as natural gas is stored today, i.e. where conditions allow, in depleted oil or gas reservoirs, salt horsts and aquifers.

Methods for the storage of hydrogen in liquid form will probably be based on the technique for storage in excavated rock caverns which has been developed and applied for the storage of LPG (liquified petroleum gas). It would seem justified, therefore, to give an account of existing facilities for LPG and other cryogenic liquids and of current research and development work concerning the storage of LNG.

The motive for underground storage is an attempt to achieve effective protection against intentional and unintentional damage and the extreme influence of natural disasters, and to exploit the environmental and economic advantages offered by underground storage.

The hydrogen gas storage facilities which are discussed here are entirely hypothetical and, as such, have no real geographical location or level in relation to sea level.

6.2.1.1 Storage of LPG

A number of facilities for the storage of cryogenic liquids in unlined rock caverns exist both in Sweden and abroad in locations where access to rock of suitable quality and environmental aspects have made this form of storage attractive. The facilities have all functioned satisfactorily.

There are in principle two methods for the storage of LPG in unlined rock caverns. The first involves storage at low temperatures (approximately -40°C) and low vapour pressure. The rock cavern can in this case be located near the surface, which means that construction costs are relatively low. The other method involves storage at a temperature above 0°C and at a gas pressure less than the groundwater pressure prevailing around the rock cavern. Owing to these conditions, rock caverns will be sited at relatively great depths below the groundwater table.

Esso Chemical AB have built four rock caverns at Stenungsund on the west coast of Sweden. The first rock cavern was built in 1965, and it is used to store propylene at a temperature of -40°C. The cavern has unlined walls and is tunnel-shaped. This is the most common shape for rock caverns in Sweden. The volume of the cavern is 12000 m^3 and its highest point is approximately 12 m below ground level.

The second rock cavern was brought into use in 1967 and was intended for the storage of liquid ethylene at -100°C and at atmospheric pressure. After filling the rock cavern with ethylene, there was unexpectedly high boil-off with a resultant leakage of gas to the surface. It was believed that the reason for this occurrence was that the influx of heat to the cavern was greater than calculated. This in turn was due to extensive propagation of fracture systems in conjunction with the fall in the temperature of the rock mass when the cavern was being filled. Since subsequent tightening of the rock walls and grouting of the surrounding rock did not give the desired result, the facility was converted for the storage of propylene. The storage facility has functioned well in this capacity, and no leakage of gas has occurred.

The third and fourth rock caverns are intended for the storage of LPG and have volumes of 60000 m^3 and 80000 m^3, respectively. The storage facilities have functioned satisfactorily since being brought into use, without leakage or abnormal boil-off.

Shell-Koppartrans, Gothenburg, have built an unlined rock cavern at Hisingen, Gothenburg, for the storage of 20000 m^3 of liquefied petroleum gas. The length, breadth and height of the rock cavern are 80 m, 15 m and 22 m, respectively. Its highest point is 90 m below the surface and its lowest point, the pump pit for infiltrating groundwater, is 120 m below the surface (see Figure 6-2). Communication with the surface is via a 750 m long tunnel and a vertical shaft for piping the product to and from the cavern and a pipe for pumping out groundwater. The tunnel and the vertical shaft were sealed off by means of concrete plugs, after which they were filled with water prior to filling with the storage product.

LPG is stored on a water bed, the level of which is held constant by pumping away the groundwater. A variable volume of vapourized LPG is stored above the liquefied product. The working pressure in the rock cavern varies between 0.2 and 0.7 MPa, and the temperature varies between +10° and +25°C.

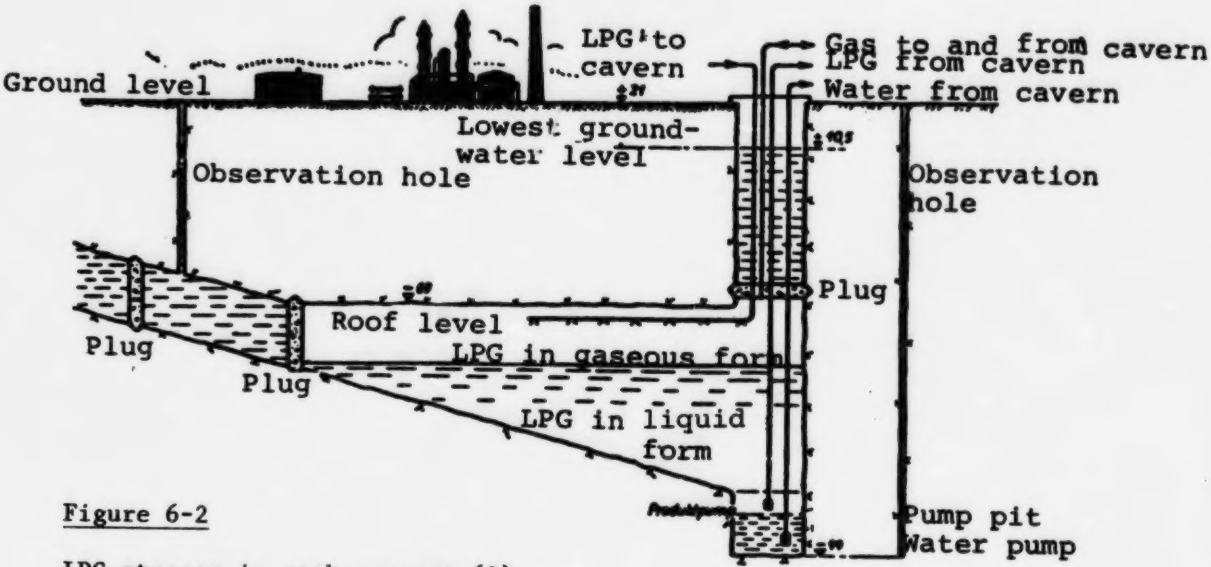

LPG to cavern
Gas to and from cavern
LPG from cavern
Water from cavern
Ground level
Lowest groundwater level
Observation hole
Observation hole
Plug
Roof level
Plug
Plug
LPG in gaseous form
LPG in liquid form
Pump pit
Water pump

Figure 6-2

LPG storage in rock caverns (3).

Research concerning hydraulic, rock mechanical, physical and thermal problems linked with the storage of LPG in unlined rock caverns has been carrried out in connection with the implemented projects. Mention can be made of an investigation (4) concerning the hydraulic conditions which must be met if the groundwater pressure is to prevent the leakage of gas via fractures, pores and faults in the rock. The investigation showed theoretically that the hydraulic gradient I_o in the downward direction to the rock cavern must exceed 1.0 if gas bubbles are not to force their way up through fractures in the rock. It was also shown that $I_o > 1.0$ cannot be met by means of a natural flow of groundwater to the rock cavern except by the introduction of an artificial system for water infiltration above the rock cavern.

A tightness test of an underground rock cavern for LPG, with a tightening arrangement with water-filled drill holes and cavern roof, has been carried out (5). The rock cavern was filled with compressed air, after which pressure, temperature and humidity were continually recorded during the test. The result showed that the daily leakage rate was less than 0.006 % in the possible pressure range for LPG.

6.2.1.2 Storage of natural gas

6.2.1.2.1 Storage in gaseous form

NG (natural gas) has for a considerable number of years been stored in depleted gas or oil reservoirs, in salt horsts and in aquifers.

In Sweden, only storage in aquifers would be applicable, since there are no depleted oil or gas fields.

In principle, the storage involves injecting gas into structures containing water (aquifers) so that the water is displaced by gas. These formations must have overlying layers of gas-tight rock types (cap rock) and must in addition be so shaped that the gas cannot leak out horizontally. The storage method is simple and has been applied with, on the whole, considerable success.

Faced with the possible introduction of natural gas into the Swedish energy system, SGU (the Geological Survey of Sweden) has mapped the occurrence of layers of rock types suitable for the storage of natural gas. The survey has shown that there is considerable storage capacity in the Skåne area of southern Sweden.

6.2.1.2.2 Storage in liquid form

The storage of LNG in unlined rock caverns is technically much more difficult than the corresponding storage of LPG. LNG at atmospheric pressure has a temperature of -161°C whereas the temperature of LPG at the same pressure is only -42°C. Projects and tests which have been carried out have shown that cryogenic liquids with temperatures down to -45°C can be stored in rock caverns without the refrigeration of the rock leading to an intolerable, progressive formation of fractures, which can only be prevented by special tightening measures.

Research and development concerning problems in connection with the storage of LNG in unlined rock caverns have in Sweden embraced the following two methods, which differ in principle.

The CryoCavern method (6) involves spraying the surfaces of the rock cavern with a thermal, vapour-tight insulation. The insulation prevents both cooling of the rock beyond low temperatures (below -45°C) at which damage may occur, and heating with resultant excessive boil-off. A detail of the CryoCavern insulation is shown in Figure 6-3.

Facilities using the CryoCavern method have been planned and designed but not yet constructed. Figure 6-4 shows a cross section of the rock cavern in a facility of this kinds. It is planned that the construction work should be carried out in the following sequence.

The four service tunnels shown in the figure are blasted out first; these are intended to serve as pilot tunnels for investigation of the geological conditions around the cavern. Holes are drilled from these tunnels around the planned perimeter of the rock cavern. The drill-holes are grouted with cement mortar and epoxy.

When a certain stretch of the rock around the cavern has been grouted, the cavern is driven by careful blasting, after which grouting is continued, and so on. When the rock cavern has been completely excavated, the insulation is applied to the rock surface. This can be done suitably from mobile scaffolding.

The CryoCavern method has been tested in a pilot facility situated near Arlanda, Stockholm. Insulation materials which had previously been laboratory-tested at the Royal Institute of Technology, Stockholm, were used in the pilot scheme. In these tests, the materials were cooled down to -196°C by using liquid nitrogen.

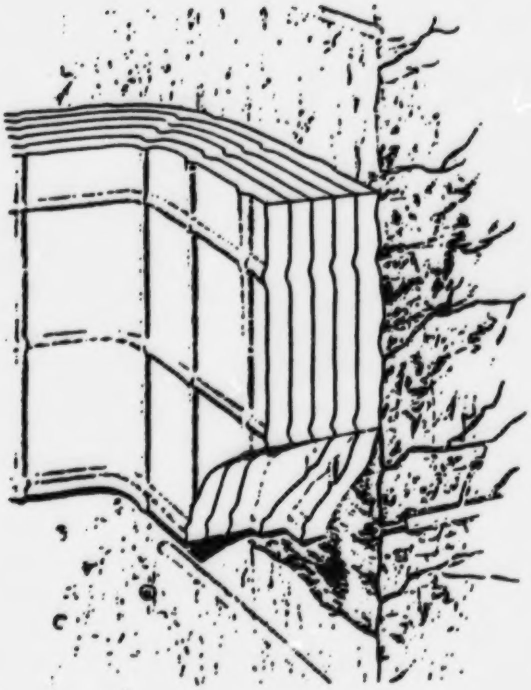


Figure 6-3

Detail of CryoCavern insulations, (6).

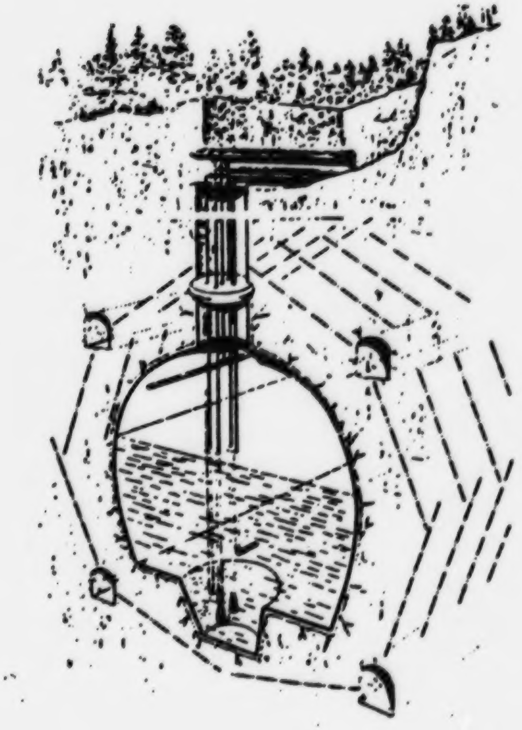


Figure 6-4

CryoCavern plant project, (6).

The results of tests in the pilot plant showed that, with a 45 cm thick layer of the insulation chosen, it would take 30 years before the rock next to the insulation cooled down to -40°C, a temperature which the rock can tolerate.

A Swedish method for storage in unlined, uninsulated rock caverns has been proposed (7). Tightness is maintained by means of a grouted zone around the rock cavern. A schematic figure of a facility of this kind is shown in Figure 6-5. The construction method is described briefly in the following.

Before excavating the rock cavern and surrounding drifts, a water injection system consisting of a tunnel and a curtain of horizontal drill-holes is constructed above the roof of the cavern. The system is pressurized with water before excavation of the rock cavern and the surrounding tunnels is begun to avoid drainage of groundwater. Simultaneously with the excavation of the tunnel, four parallel drifts are constructed in the area around the cavern. Holes for water drainage and grouting are drilled, interconnecting these four drifts and directed toward the cavern. By pumping the groundwater from the two lower drifts, the rock mass between the drill-hole curtain and the rock cavern will be drained. The drill-holes which are directed toward the rock cavern are pressurized with a grout material which solidifies at about -100°C. Grouting is started at the same time as cooling down of the rock cavern is initiated, and the grouting pressure is maintained throughout the operational life of the facility. Major fractures will be filled with grout material, which will tend to flow towards the rock cavern where there is a colder environment. It will finally freeze, thus tightening the fractures. A tightening zone of frozen grout material will thus be formed around the LNG storage facility.

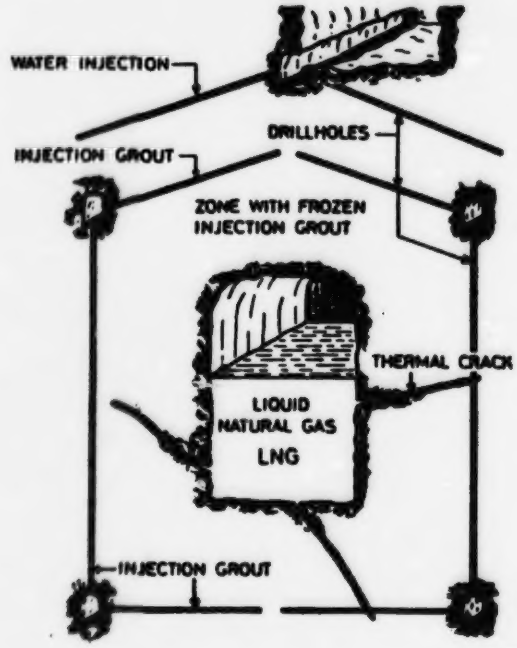


Figure 6-5

Conceptual layout of rock cavern for LNG storage (7).

6.2.2 Storage of compressed hydrogen gas

6.2.2.1 Geological storage

6.2.2.1.1 General

The necessary conditions for the geological storage of compressed hydrogen gas can probably be found at several locations in Sweden. This judgement is based on the results arrived at by SGU when a survey was made of aquifers suitable for the storage of liquefied natural gas. The survey showed that there are aquifers in the sedimentary areas in Västergötland, Östergötland, Närke, the Siljan area and on Öland, but that the requirements for tightness when storing natural gas are not fulfilled. The opinion was that an aquifer should lie at least 400 m below ground level, a condition which was not met in these areas.

Geological conditions on Gotland are, on the other hand, favourable, but the distance to the mainland is so great that it is unlikely that storage there could be implemented to any advantage.

In the southern and western parts of the Vättern basin, there are porous layers of rock containing water at a depth of 200 m. It is quite possible that there are aquifers to be found at greater depths which would be suitable for the storage of gas.

The greatest possibilities of finding geological formation suitable for the storage of gas are likely to be in Skåne. Within the Ystad-Trelleborg-Landskrona area, there are sedimentary layers of rock at various depths and of such thickness that considerable storage volumes may be likely. The extent of the palaeozoic and mesozoic areas suitable for the storage of gas is shown in Figure 6-6.

6.2.2.1.2 Storage method

It may be reasonably assumed that the storage of hydrogen gas can be carried out in the same way as that of natural gas. The storage pressure will be 5 - 10 MPa.

6.2.2.1.3 Cost

Cost estimates for hydrogen storage concepts dealt with in this report have been made on the following assumptions

- fixed prices at the 1978 price level
- 4 % real rate of interest
- the depreciation period is 60 and 10 years for buildings and mechanical equipment, respectively

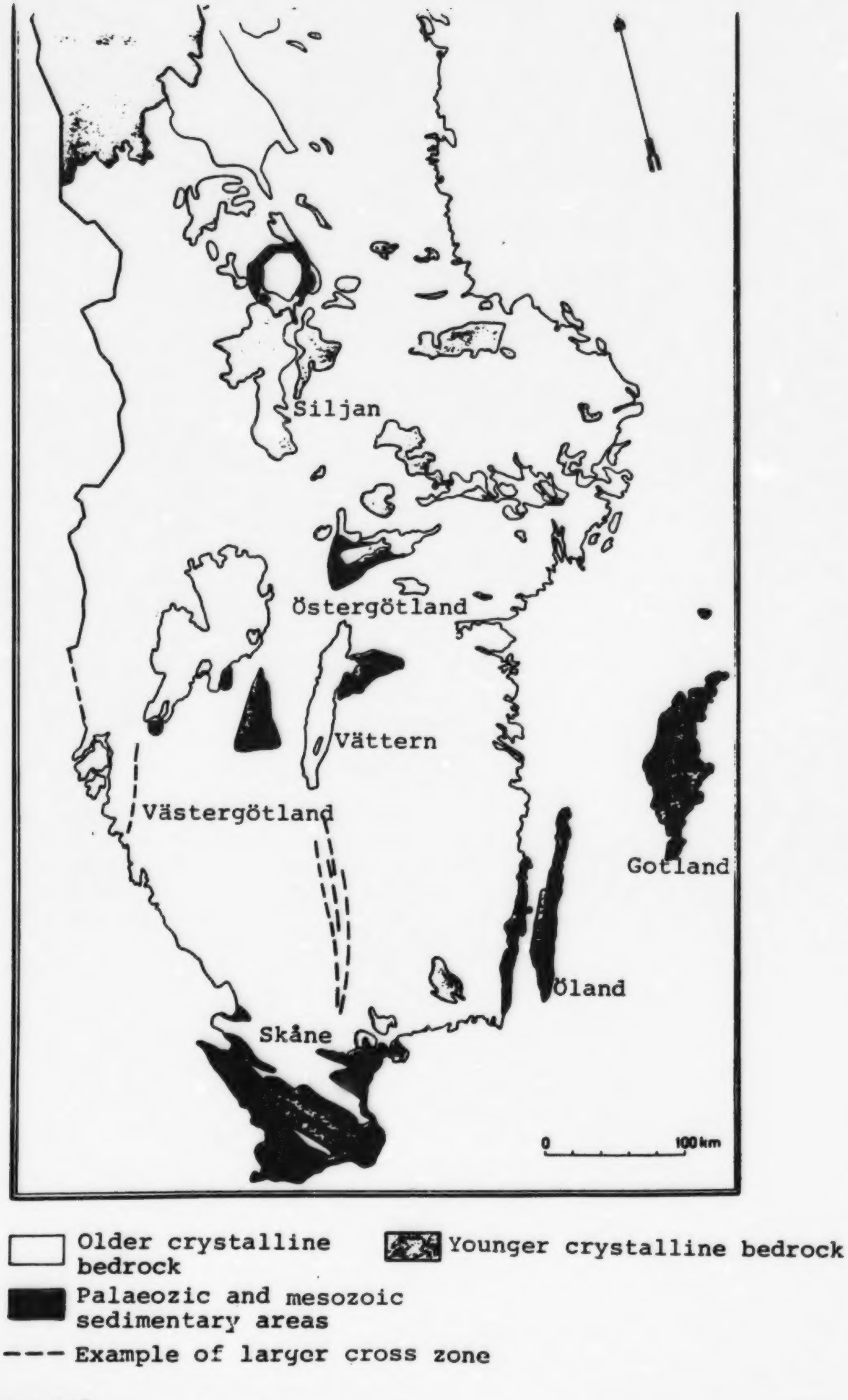

Siljan
Östergötland
Vättern
Västergötland
Gotland
Öland
Skåne
0
100 km
☐ Older crystalline bedrock
▨ Younger crystalline bedrock
■ Palaeozic and mesozoic sedimentary areas
--- Example of larger cross zone

Figure 6-6

Aquifier areas in Sweden.

- the maintenance cost is 0.2 % and 1 % of construction cost and equipment cost, respectively
- the operational cost is 0.03 cr/Nm^3 GH_2 or 2.3 cr/GJ
- the product storage cost at the consumer level is 1/10 of the annual storage cost.

The cost of storing hydrogen gas in aquifers is calculated on the basis of cost information concerning the corresponding storage of natural gas. The investment cost of a natural gas storage facility, including exploration, local pipelines, installations, drill-holes and cushion gas amounts to approximately 0.80 cr/Nm^3 NG. The corresponding costs for the storage of hydrogen gas are estimated to be 0.75 cr/Nm^3 GH_2 or 59 cr/GJ.

The annual storage cost and the product storage cost have been calculated to be 7.8 cr/GJ and 0.78 cr/GJ, respectively.

6.2.2.2 Storage in excavated rock caverns. Concepts.

6.2.2.2.1 General

It is assumed that facilities of this kind will be constructed within an area with crystalline rock of good quality. Certain fracture and crush zones can, however, be accepted, in which case the rock caverns will be aligned as far as possible across the plane of fracture, with special reinforcement and tightening measures being taken.

Calculations are made to provide an analysis of the stability of the rock cavern on the basis of investigation results. Necessary consideration should be given to seismic effects.

The rock cavern is designed with a suitable shape, with spans of between 20 and 25 m. The rock cover is determined having regards to the gas pressure chosen.

The distance between the rock caverns is chosen so that stability is not put at risk and so that future blasting will not have any effect on parts of the facility already in operation.

The roof and walls of the rock cavern are reinforced to prevent rockfalls.

It is assumed that each rock cavern will be constructed to a size which is compatible with current techniques and experience of underground construction. At the same time, the specific storage cost, cr/Nm^3, should be kept to a minimum and should be of the same order as that for storage in containers above ground.

6.2.2.2.2 Rock investigations

Pre-investigations of the area in question are carried out before and during the design of the facility. The following investigations are carried out in connection with the initial geological mapping and analysis:

- Determination of the level of the rock surface.
- Seismic investigations.
- Core samples with geological survey and investigations regarding filling of fractures. Determination of the groundwater level.
- Measurement of water losses and possibly TV scanning of drill-holes.
- Evaluations in connection with early driving of transport tunnels.

Rock sections are investigated where necessary during the construction period, using one or several of the pre-investigation methods. In addition deformation measurements are done inside the rock caverns.

6.2.2.2.3 Storage methods

The gas is stored at high pressure on a water bed. The water bed is linked to a water reservoir, the water level of which is the same as that of the groundwater table. In this way, the gas pressure can be held constant during operation. The temperature of the gas is the same as the temperature prevailing at the depth of the facility.

6.2.2.2.4 Layout

The facility is designed as a number of parallel rock caverns at a level which is determined by the situation of the groundwater table and by the operational pressure. The latter must be lower than the prevailing hydrostatic pressure.

The rock caverns have flat floors and walls and a vaulted roof. The breadth and height are approximately 25 and 35 m, respectively.

Above the cavern's roofs and below their floors, service tunnels are constructed, from which holes are drilled connecting the tunnels with each other and other holes running in the direction of the cavern in question.

The connecting drill-holes are designed to maintain the groundwater pressure, while the others are used for grouting the rock nearest to the cavern to make it water-tight. The tunnels are also used for geological investigations.

In a plane above the highest service tunnels, a system of tunnels and drill-hole curtains is constructed for the infiltration of water. This is to prevent drainage of water from the rock while service tunnels and rock caverns are being excavated.

Rock caverns with a transport tunnel and vertical shafts for gas pipes are shown in Figures 6-7, 6-8 and 6-9. The transport tunnel is filled with water before the facility is brought into operation and is simultaneously connected to a pressure-maintaining reservoir at the level of the groundwater table.

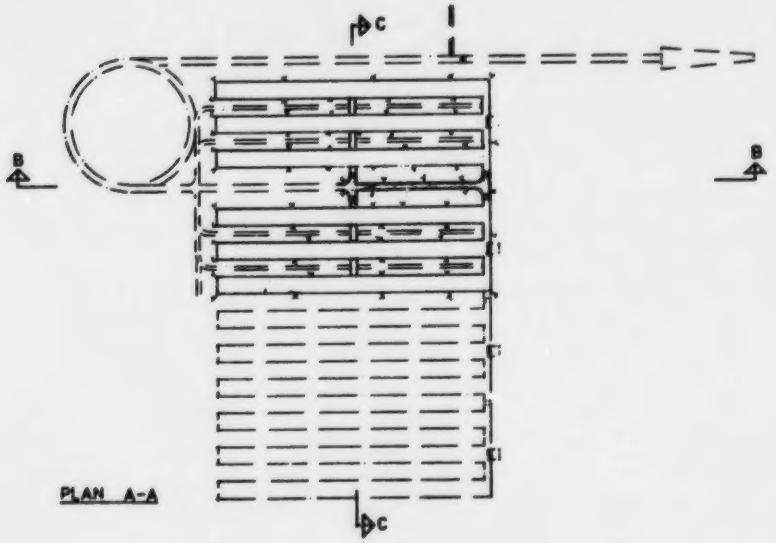

C
B
B
PLAN A-A
C

Figure 6-7

Plan of rock storage facility.

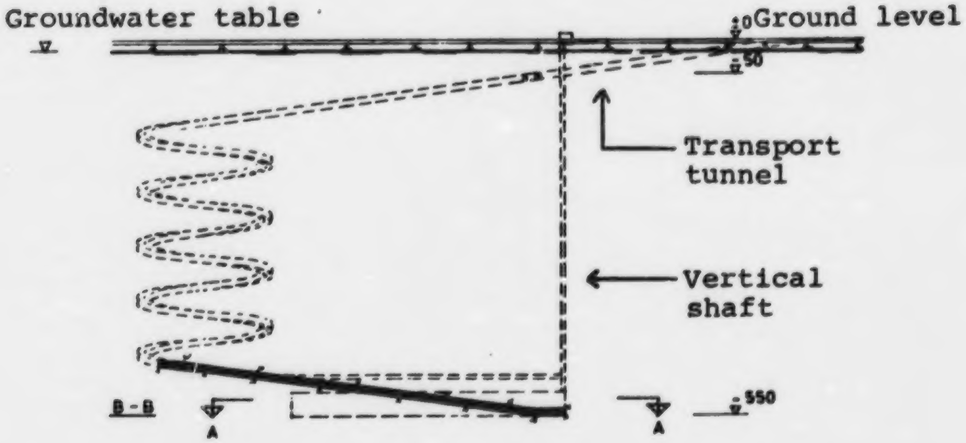

Groundwater table
±0Ground level
-50
Transport tunnel
Vertical shaft
B-B
A
A
-550

Figure 6-8

Longitudinal section of rock cavern.

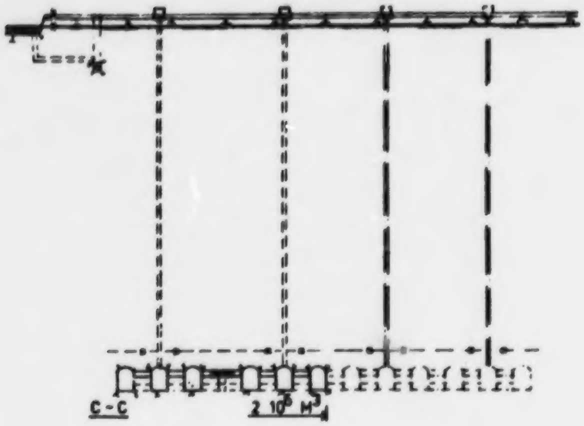


Figure 6-9

Cross section of rock caverns.

Storage facilities with varying size, storage pressure and storage temperature (see Table 6-1) have been studied.

Table 6-1

Storage volume Nm^3	Storage pressure MPa	Volume of rock cavern m^3
100x10^6	5	2x10^6
100x10^6	7.5	1.33x10^6
100x10^6	10	1x10^6

Storage pressure of 5, 7.5 and 10 MPa mean that the roof of the rock cavern must be located at least 500, 750 and 1000 m, respectively, below the groundwater table, if the groundwater pressure is to maintain the gas tightness of the storage facility.

6.2.2.2.5 Structural design

The rock caverns are unlined, with the exception of the roofs, which are given a shotcrete lining. There may be reinforcement of the rock in the form of bolting and grouting. Grouting may also be necessary if the rock is abnormally porous.

6.2.2.2.6 Construction

The transport tunnel and shaft are excavated with every imaginable precaution being taken to prevent drainage of the rock. Before the rock caverns are excavated, the system of tunnels and drill-hole curtains for infiltration of water is constructed and pressurized, above the roof of the rock cavern.

The rock excavation is planned and carried out with careful blasting so that momentary movements and permanent deformations in the remaining rock are as small as possible, i.e. so that any reduction of the strength and stability of the rock is kept at a minimum during excavation.

The extent and type of rock reinforcement depend on the characteristics of the rock. In view of the demand for stability and tightness, it is possible that one or several of the following measures will be taken:

- Bolt-anchored, reinforced shotcrete on the roof.
- Local reinforcement of the wall and roof of the rock cavern with concrete structures.
- Grouting of fractured rock, possibly in the form or pre-grouting.

6.2.2.2.7 Construction time

A calculation has been made of the construction time required for construction of the water infiltration system, transport tunnel, rock caverns and concrete structures, and for the installation of drainage systems and pipes for the stored product. It has been assumed that excavation of rock is done on a two-shift system.

Storage depth below groundwater table m	Construction time years
500	6
750	6.5
1000	7

It should be possible to build those parts of the facility which are situated above ground simultaneously with the work underground, so that the time periods given can be assumed to refer to the total construction time.

6.2.2.2.8 Cost

Calculations have been made of the cost for the underground parts of a facility for the storage of 10^8 Nm^3 GH_2, Table 6-2. The cost does not cover, for example, arrangements for reception and distribution above ground. This is of minor importance considering that construction costs predominate totally.

Table 6-2

Hydrogen storage costs for a rock cavern.

Depth below groundwater table m	Pressure MPa	Volume of rock cavern m^3	Cost of facility Mcr	Cost of facility cr/GJ
500	5.0	$2x10^6$	345	270
750	7.5	$1.33x10^6$	335	262
1000	10.0	$1x10^6$	355	278

The capital cost of the storage facility (cr/GJ) as a function of the depth below the groundwater table is shown in Figure 6-10. The annual storage cost and the product storage cost have been calculated at 16.6 cr/GJ and 1.66 cr/GJ, respectively.

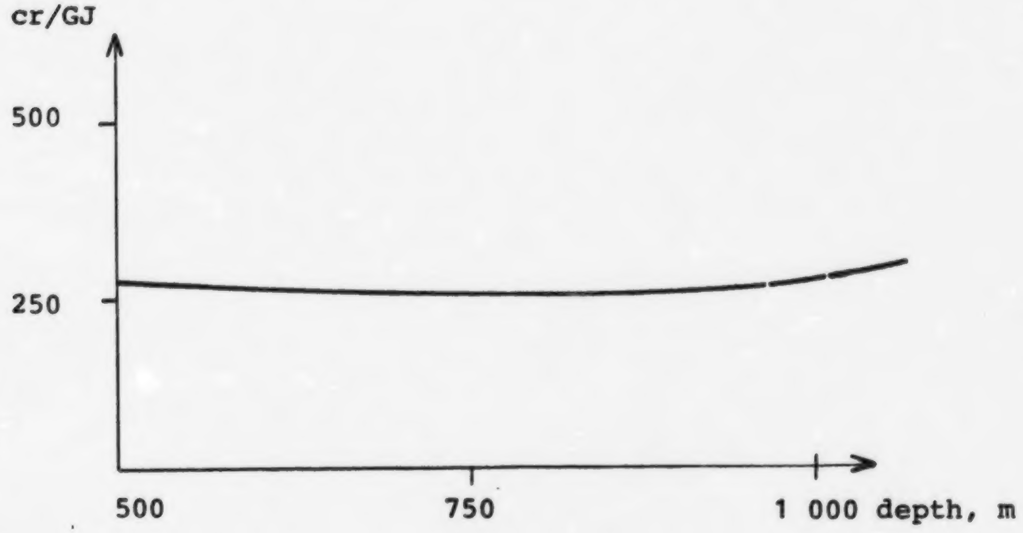


Figure 6-10

Investment cost as a function of the depth below the groundwater table.

6.2.3 Storage in liquid form

6.2.3.1 General

It can be predicted that underground storage of liquid hydrogen can be in

- unlined, uninsulated rock caverns,
- unlined rock caverns, but with considerable thermal insulation,

- lined, well-insultated rock caverns,
- containers situated in unlined rock caverns.

The storage of liquid hydrogen in rock caverns, unlined or lined, insulated or uninsulated, can without exaggeration be claimed to be an extremely complex technical problem, judging by the difficulties met by engineers and researchers in the development of methods for the storage of liquefied natural gas in similar structures. It is hardly likely that any solutions exist which have been developed beyond the idea stage. The concepts which are discussed in this section are to some extent based on current proposals for the storage of LNG.

In principle, storage in containers situated in rock caverns is carried out in the same way and with the same kind of structural design for the containers as in the case of storage above ground. For this reason, it is not treated here but in Section 6.3.

Storage is at a pressure between atmospheric pressure and critical pressure, 1.28 MPa. The temperature will thus be in the range between -250°C and -240°C.

The demands on rock quality, scope of geological investigations, stability of the rock caverns, etc must be set at least as high as those in connection with the storage of hydrogen in a gaseous form.

The general shape and construction of the storage facility do not differ greatly from those of a facility for the storage of compressed hydrogen gas. The volume of the rock caverns will of course be much less than for an equivalent amount of gas.

6.2.3.2 Unlined, uninsulated rock caverns

6.2.3.2.1 Storage method and construction

Liquid hydrogen is stored at 0.1 - 1.2 MPa within a temperature range of -250°C to -240°C. The method is in principle the same as that put forward by Ulf Lindblom for the storage of LNG.

The rock caverns are shaped and surrounded by a grouted sealing zone in ways described in the section on LNG storage.

6.2.3.2.2 Cost

The investment cost of a storage facility for LNG amounts to approximately 1.50 cr/Nm^3 gaseous NG. It is not unlikely that the cost for the storage of liquid hydrogen is of the same magnitude, that is 1.50 cr/Nm^3 GH_2 equal to 117 cr/GJ. The cost given is only for the underground parts of the facility including installation.

The annual storage cost using the value given above is 9.7 cr/GJ and the product storage cost is 0.97 cr/GJ.

6.2.3.2.3 Construction time

In the case of a facility with a storage capacity of 300×10^3 m^3 LH_2, the time for completion of the underground part is estimated at 2.5 years. Buildings and process equipment above ground can for the most part be constructed at the same time as the underground work is going on, so that the total time will only marginally exceed the time for completion of the underground part.

6.2.3.3 Unlined, insulated rock caverns

6.2.3.3.1 Storage method and construction

Storage method

The method is based on sealing and thermal insulation of the rock surfaces, i.e. in principle the same method which is today marketed under the name CryoCavern for the storage of LNG. It is assumed that materials which can withstand cooling down to -250°C are available.

The hydrogen product is stored at 0.1 MPa and -250°C or at 1.2 MPa and -240°C.

Construction

The rock caverns are located at a depth below ground level which is at least 100 m. Excavation must be carried out with the most sophisticated technique available so that the rock surfaces below the insulation layer are as smooth and fracture-free as possible. It is important that the rock caverns should be positioned with consideration to the main stresses prevailing in the rock.

The movement of vapour via fractures and pores in the rock in the direction of the rock cavern may cause the insulation layer to break loose. This movement of vapour is prevented by grouting fractures > 0.4 mm with cement and fractures < 0.4 mm with plastic.

In order that the insulation material should adhere to the rock walls, these are given a layer of epoxy glue, which also has the function of preventing leakage of groundwater into the cavern.

The shape of the rock cavern is outlined in cross section in Figure 6-11. Geological investigations and drilling of holes for grouting of the rock are carried out from the four service tunnels, which are excavated before the rock cavern. The tunnels are also equipped with devices for the detection of gas.

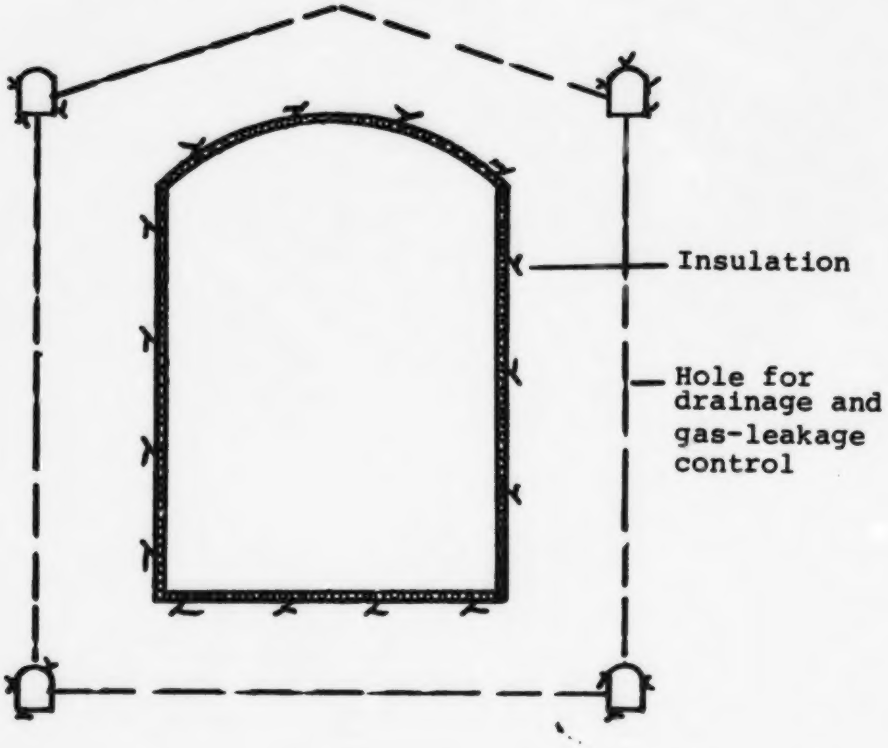


Figure 6-11

Cross section of a rock cavern for storage of LH_2. Conceptual design.

6.2.3.3.2 Cost

The investment cost of the facility is estimated at 1.50 cr/Nm^3 GH_2 or 117 cr/GJ. The cost does not include the cost of parts of the facility above ground. The annual storage cost and the product storage cost have been calculated to be 9.7 cr/GJ and 0.97 cr/GJ, respectively.

6.2.3.3.3 Construction time

It is estimated that completion of a facility with a storage volume of 300×10^3 m^3 LH_2 would take approximately 2.5 years.

6.2.3.4 Lined, insulated rock caverns

6.2.3.4.1 Storage method

Liquid hydrogen is stored at a pressure of 0.1 or 1.2 MPa, the hydrogen product thus having a temperature of $-250^\circ C$ or $-240^\circ C$, respectively.

6.2.3.4.2 Layout

The facility comprises a number of parallel rock caverns situated about 100 m below ground level. Communication from the caverns to the surface is by a shaft for the product pipeline and by transport tunnels. The shaft and tunnels are sealed with concrete plugs.

Above the roof of the rock cavern and below its floor, very small tunnels are constructed from which a curtain of holes is drilled between the tunnels. The function of the tunnels and the drill-holes is to drain as completely as possible the rock mass between the drill-holes and the cavern and to make possible inspection of the rock and discovery of any leakage of gas that may arise.

6.2.3.4.3 Structural design

The walls of the rock cavern are given a gas-tight lining of reinforced concrete and a layer of thermal insulation. The concrete itself is not gas-tight and must therefore be given a sealing layer, which can be in the form of a non-corrosive steel sheet. The sheet steel can either be applied to the concrete surface towards the rock cavern or be cast into the concrete.

The concrete lining, which suitably should have a thickness of at least 300 mm, can be given heating coils to prevent condensation of water vapour behind the sheet at the same time as the temperatures of the rock and of the concrete are prevented from sinking to levels low enough to cause damage.

The thermal insulation, which can be perlite, is applied between the concrete lining and an inner shell of steel.

6.2.3.4.4 Construction

The structural design of the storage facility is quite conventional and requires no more than normal care in planning and construction. The concrete lining with tight steel sheet is of the type under consideration for lining reactor caverns in nuclear power stations located in rock.

6.2.3.4.5 Construction time

The construction time for a facility with a capacity of 300×10^3 m^3 LH_2 is estimated at 3 years.

6.2.3.4.6 Cost

The capital cost for the underground part of the storage facility is estimated at 1.8 cr/Nm^3 GH_2 (141 cr/GJ).

The annual storage cost has been calculated to be 11.7 cr/GJ and the product storage cost 1.17 cr/GJ.

6.2.4 Research and development

6.2.4.1 Storage of compressed hydrogen gas

6.2.4.1.1 Geological storage

To the extent that the results of studies already made or of future studies concerning the storage of natural gas in Sweden are inadequate or inapplicable for the storage of hydrogen gas, future work should be directed towards the exploration of suitable areas for the storage of hydrogen gas, analyses of capacity and cost, identification of problems regarding installation, operation and maintenance, safety and the environment etc. Study visits to identical or similar storage facilities abroad form an integral part of this development work.

6.2.4.1.2 Storage in excavated rock caverns

Storage in artificial rock caverns does not differ in principle from storage in aquifers. It should not therefore be necessary to carry out any special research or development work on storage in excavated rock caverns.

6.2.4.2 Storage in liquid form

6.2.4.2.1 Storage in excavated rock caverns

A great many problems of an extremely difficult nature will have to be solved before commercial storage facilities can be built. The extremely low temperature of the product to be stored results in propagation of fracture systems with consequent unacceptable boil-off and leakage of gas. Research should therefore be directed in the first place towards finding means and methods which prevent these difficulties.

The nature of the problem is affected by whether the rock caverns are insulated or not.

Unlined, uninsulated rock caverns

Research work should be concentrated on the following problems:

- Development of grouting materials for making the rock gas-tight.
- Grouting methods.
- Heat flow in rock.
- Stresses in rock resulting from thermal load.
- Methods for lowering the temperature of the rock in connection with the first filling.

Unlined/lined, insulated rock caverns

- Development and testing of suitable insulation materials.
- Development of methods for application of insulation to rock surfaces and to concrete surfaces.

- Design of concrete lining and sealing layer.
- Movement of vapour against the insulation layer (which may cause frost damage).

On the basis of the research results arrived at, a pilot storage facility can be designed and constructed, on a reasonably large scale. Only when a pilot facility of this kind has verified the research results can commercial plants be built.

6.2.5 Environmental and safety aspects

Underground storage in natural or artificial reservoirs offers a whole range of advantages as compared with storage in tanks above ground.

Areas of natural beauty on the coasts or near centres of population need not be used for ugly tank facilities but can retain their recreational value if storage is located underground. Where land is in short supply, underground storage is in addition a tenable alternative from the purely economic point of view.

From the safety point of view, underground storage should be unbeatable. It can be assumed that foreseen and unforeseen hitches in operation and maintenance will occur less frequently and will be easier to deal with successfully than is the case with a storage facility consisting of a large number of containers above ground in close proximity to each other. Protection against acts of war and terrorism is also unquestionably easier when the hydrogen product is stored below ground.

6.3 Storage above ground

6.3.1 General

The development of systems for this type of storage has not shown any remarkable progress during the last decade. This is probably not least because hydrogen gas is in the vast majority of cases consumed at the place of production and the amount produced has on the whole corresponded to the amount consumed in the same, or a nearby industrial plant. Any small surplus has been burnt, since this is the cheapest alternative.

There has, however, been som development within the conventional systems. In the USA, this has been a result of the need for hydrogen in the space programme. Development has above all taken the form of a volume-wise increase in the dimensions of tanks for liquid hydrogen and of raising the storage pressure for products in gaseous form.

A review, based on studies of the literature, of the alternative possibilities for above-ground storage, including certain development trends, is given in the following sections.

Since the literature on the subject is sparse, a brief summary has also been made of experience gained in storage of LNG products. This is in order to give, if possible, certain indications of future development possibilities.

6.3.1.1 Storage of LNG

The storage of LNG presents problems similar in nature to those connected with liquid hydrogen, which is why a brief summary in this field can be justified.

Storage of LNG is carried out in tanks of considerably greater size than those being discussed for hydrogen. Sizes of the order of 50000 m^3 are common, for example, at Avonmouth (9), and sizes up to 120000 m^3 are being constructed, for example, by Gaz de France at Montoir.

For sizes up to 50000 m^3, the traditional structural design has been as follows (see also Figure 6-12):

- an inner cylindrical tank of cryogenic metal such as aluminium alloy or 9 per cent nickel steel,
- an outer steel tank which serves as an outer static protective barrier and contains the insulation and the gas (~ 0.04 %) continuously evolved from the liquid gas,
- insulation, which consists of perlite between the shells and fibre-glass for the roof. Insulation of the base is in the form of foam glass blocks, but to prevent freezing the tanks are sometimes constructed either on columns which allow circulation of air or with heating of the foundation slab.

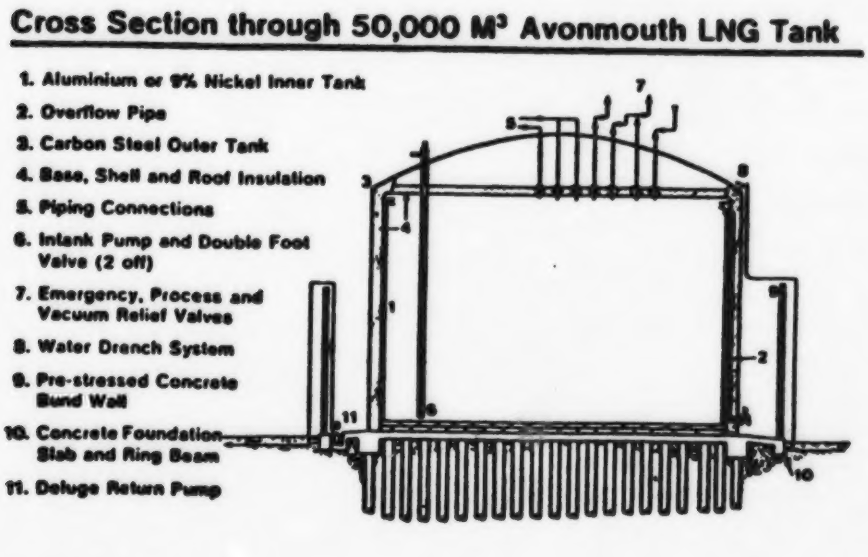

Cross Section through 50,000 M³ Avonmouth LNG Tank
1. Aluminium or 9% Nickel Inner Tank
2. Overflow Pipe
3. Carbon Steel Outer Tank
4. Base, Shell and Roof Insulation
5. Piping Connections
6. Intank Pump and Double Foot Valve (2 off)
7. Emergency, Process and Vacuum Relief Valves
8. Water Drench System
9. Pre-stressed Concrete Bund Wall
10. Concrete Foundation Slab and Ring Beam
11. Deluge Return Pump
1
2
3
4
5
6
7
8
9
10
11

Figure 6-12

Schematic diagram of an Avonmouth LNG tank, (9).

In the case of the larger tanks (80 000 - 120 000 m^3), economic factors have led to a development towards construction of the inner tank as a thinner membrane of a cryogenic metal and of the outer tank in concrete. This is still under development, and it also appears to be unclear whether there are applicable regulations for concrete provided by the authorities for these areas of use.

6.3.2 Hydrogen in gaseous form

Hydrogen in gaseous form can be stored under

- high pressure

or combined to form

- hydrides.

6.3.2.1 High pressure containers

This is the most common method for the storage of hydrogen gas, which also means that existing container vary widely with respect to volume, pressure, material and shape.

Containers have been built both as horizontal and vertical cylinders and as spherical ones, the latter most often for larger volumes and today in growing numbers at industrial plants and gasworks. The pressure goes up to 100 MPa for larger pressure vessels, but it is in the USA, for example, limited to 16.5 MPa for transportation vessels.

The high pressures involved mean that rigorous demands are made on the wall materials. Walls may attain thicknesses of over 30 mm with resultant problems of welding stress. The measures which have to be taken in connection with these problems lead to cost increases.

Economic considerations force the appearance of large containers, even if erection is made more difficult at sizes above 5000 m^3. The investment cost is estimated to be 1275 cr/Nm^3 GH_2 at 1.6 MPa.

6.3.2.2 Metal hydride storage

This idea for storage is under development and has not yet achieved commercial application, although pilot storage facilities are in operation in the USA.

The method, which makes possible the compact storage of hydrogen at normal pressures and temperatures, involves the use of a metal alloy, such as FeTi, as carrier of hydrogen ions. Heat is released during the hydriding process and heat must be applied to release the hydrogen.

It would seem to be difficult to forecast large-scale storage by means of hydrides, but the method has a future for the safe handling of limited quantities. Examples of problems which remain to be solved are:

- cost and weight of the alloy,
- desirability of a low dissociation temperature,
- rate of formation and dissociation.

Metal hydride storage is dealt with in detail in Chapter 12.

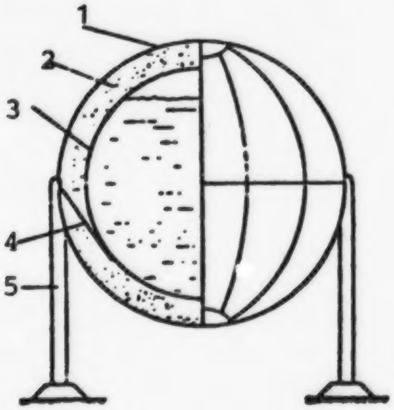
6.3.3 Liquid hydrogen

The storage of hydrogen in liquid form requires a low temperature (-253°C), but a large storage capacity can be attained as the volume is reduced to 1/790 of the volume of the gas under atmospheric pressure.

6.3.3.1 Containers

Larger tanks for liquid hydrogen are without exception made as double-walled, spherical, vacuum-insulated vessels. The largest volume to date is 5000 m^3 (NASA), which gives an inner radius of 10.6 m. A tank of this kind is constructed with an inner container made of some aluminium alloy, an outer container of steel, and, in between, a vacuum space (~ 10^{-4} bar) with a non-inflammable insulating layer of, for example, Perlite (10), Figure 6-13.

A tank of this kind also has a large amount of ancillary equipment for emptying and topping up, handling of gas resulting from evaporation (~ 0.1 % per day), safety devices etc. It is not possible to prevent evaporation entirely. The evolved gas is most commonly either used for heating purposes or re-condensed and fed back into the container. Experience has shown that relative evaporation decreases with increased tank volume.



1. Outer container
2. Insulation space
3. Inner container
4. Suspension
5. Structural support

Figure 6-13

Liquid hydrogen storage tank.

6.3.3.2 Handling of liquid hydrogen

Filling and emptying of tanks is done via metal pressure hoses in accordance with the regulations in force for the handling of pressurized gas.

There are three different methods for handling hydrogen to or from tanks, namely:

- pumping,
- compressed gas,
- evaporators.

Pumps have been developed primarily in connection with space technology, and there are various types on the market. There is a risk of cavitation, but this can be combatted by means of special measures, such as overpressure in the tank.

Only media such as helium or hydrogen can be considered for use as pressure gas. Helium is expensive and is used only for special projects.

The use of evaporators exploits the evaporation of hydrogen itself as the driving force via a special chamber from which the required amount is led back in to the tank. The method is used for example in road and sea tankers in order to attain the overpressure mentioned above as necessary for pumps.

Measurements of the amount of hydrogen is difficult, and no satisfactory solution has been found. There are flow-through meters on the market. but at two-phase flow which occurs at the beginning of the tank-filling operation these meters do not function satisfactorily.

In this context, a note should be made of the importance of compressors. Compressors are used at all stages where hydrogen is concerned in order to attain the requisite pressure level in storage, transmission and distribution, and naturally also in conversion to the liquid form. The conventional compressor cannot be used without comprehensive modifications on account of the tendency of the material to embrittlement. The low thermal value of hydrogen gas relative to that of natural gas (1:3) means that the volume transmitted becomes three times as great. This makes it obvious that every improvement with regard to the compressor and to the reduction of corresponding work is advantageous.

6.3.3.3 Safety considerations

Hydrogen is a highly flammable gas. Its lower and upper flammability limits in air at 20°C and 0.1 MPa are 4 % and 74.5 %, respectively. The minimum auto-ignition temperature at 0.1 MPa is 570°C. The minimum energy of ignition is low, at least ten times lower than that of hydrocarbons. However, because of its lightness and high diffusion velocity, hydrogen is more easily dissipated than petroleum gases and, in the case of ignition, hydrogen fires are less dangerous than hydrocarbon fires because they are concentrated, rapid and slightly radiant. Some precautions to be taken in the handling and storage of hydrogen are briefly reviewed.

Safety regulations must be prepared, and all personnel must be informed about the hazards related to the handling of hydrogen.

The storage of hydrogen in liquid form demands comprehensive safety precautions primarily on account of the risk of explosion. The demands for tightness are high, as are those for preventive fire precautions and surveillance. Thus, equipment and containers must be thoroughly leak-tested before being used and thereafter continually at specified intervals. A hydrogen storage plant must be provided with efficient fire-fighting equipment, able to be brought into action in a few seconds and capable of protecting the environment until the fire is extinguished.

6.3.3.4 Cost

The investment cost of a large-scale storage facility for LNG amounts to about 1.3 cr/Nm^3 NG at 1978 prices (7). It is not unlikely that the volume cost of storing liquid hydrogen will be of the same order, i.e. 102 cr/GJ. The investment cost for the largest storage tanks of today amounts to about 250 cr/GJ.

6.4 Alternative energy sources

The competitiveness of hydrogen as an energy source is dependent on the cost for alternative energy sources. One part of this cost is the storage cost, which has been estimated for natural gas (NG and LNG), methanol and petrol.

Thus, the investment storage cost for NG stored underground in aquifers and rock caverns is estimated to be 21 cr/GJ and 90 cr/GJ, respectively. Storage of LNG in rock caverns is estimated at 39 cr/GJ. Storage of LNG in tanks above ground is estimated at 34 cr/GJ.

The investment storage cost for methanol in lined rock caverns and in tanks above ground is approximately 20 cr/GJ and 23 cr/GJ, respectively.

The investment storage cost for underground storage of petrol in unlined rock caverns is estimated at 7.1 cr/GJ. Storage in tanks above ground costs about 11.4 cr/GJ.

Estimates of investment costs, annual storage costs and product storage costs, based on the assumptions given in 6.2.2.1.3, are given in 6.5.

6.5 Summary

In the event of hydrogen being used as a main energy carrier in a future energy supply system, large storage capacities will be necessary in order to neutralize differences between production and consumption.

Hydrogen can be stored as a compressed gas or in liquid form at a very low temperature, -253°C. For Sweden, it is anticipated that the following storage alternatives are potentially possible:

- underground, in gaseous form, in extremely large, geologically formed reservoirs (aquifers),

- underground, in gaseous or liquid form, in large rock caverns,

- underground, in gaseous or liquid form, in large containers located in rock caverns,

- above ground, as a liquid, in large, cryogenic containers.

Underground storage

Suitable formations for geological storage can be expected to be found at many places in Sweden, especially in Skåne in southern Sweden. In regions where conditions for geological storage do not exist, there are good chances of finding hard rock convenient for excavated rock caverns.

The storage of hydrogen in a liquid form has been considered conceivable in:

- unlined, uninsulated rock caverns,
- unlined rock caverns with heavy thermal insulation,
- concrete-lined rock caverns with heavy insulation,
- containers located in unlined rock caverns.

The storage of liquid hydrogen in rock caverns, whether lined or unlined, insulated or uninsulated, is an extremely complex technical problem, judging by the difficulties which have been met by engineers and researchers during the development of methods for the storage of liquefied natural gas in storage facilities of this type. The concepts which are discussed in this chapter are in part based on concepts currently being considered for the storage of LNG.

Comprehensive research, development and design work must be carried out before commercial underground storage facilities for hydrogen can be brought into operation.

Above-ground storage

Large-scale storage of hydrogen can be carried out

- as a gas at high pressure in containers with pressures up to 100 MPa,
- as a liquid at low temperatures in double-walled spherical containers,
- as a solid in the form of hydrides.

Only the second method is economically competitive at present.

Storage cost

Investment costs, annual storage costs and product storage costs at 1978 prices and 4 % real rate of interest have been estimated and are given Table 6-3. Storage costs for alternative energy sources are summarized in Tables 6-4 and 6-5.

Table 6-3

Storage costs for hydrogen.

Storage method	Investment cost		Annual storage cost		Product storage cost	
	cr/Nm^3 GH$_2$	cr/GJ	cr/Nm^3 GH$_2$	cr/GJ	cr/Nm^3 GH$_2$	cr/GJ
Underground storage						
Storage in gaseous form						
Geological storage	0.75	59	0.10	7.8	0.010	0.78
Storage in unlined, uninsulated rock caverns	3.45	270	0.21	16.4	0.021	1.64
Storage in liquid forms						
Storage in unlined, insulated rock caverns	1.50	117	0.12	9.7	0.012	0.97
Storage in lined, insulated rock caverns	1.80	141	0.15	11.7	0.015	1.17
Storage above ground						
Storage in liquid form						
Storage in large tanks	1.30	102	0.12	9.4	0.012	0.94

Table 6-4

Storage costs for natural gas, cr/GJ.

Storage method	Investment cost	Annual storage cost	Product storage cost
Underground storage			
Storage in gaseous form			
Geological storage	21	2.8	0.28
Storage in unlined, uninsulated rock caverns	90	5.5	0.55
Storage in liquid form			
Storage in unlined, insulated rock caverns	39	3.2	0.32
Storage above ground			
Storage in liquid form			
Storage in large tanks	34	3.1	0.31

Table 6-5

Storage costs for methanol and petrol, cr/GJ.

Storage method	Investment cost		Annual storage cost		Product storage cost	
	methanol	petrol	methanol	petrol	methanol	petrol
Underground storage						
Storage in lined rock caverns	20		1.7		0.17	
Storage in unlined rock caverns		7.1		0.5		0.05
Storage above ground						
Storage in large tanks	23	11.4	2.1	1.0	0.21	0.10

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6-34

7. TRANSMISSION

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7.1 General considerations

Present-day technical experience permits the transmission of hydrogen either by pipeline in a gaseous form or in bulk in a liquid form. These and other transmission systems, such as pipelines for liquid hydrogen, will be discussed in detail.

The economy of a transmission system and its practicability depend upon the end-use of the hydrogen. If only liquid hydrogen is required for use in vehicles, the cost of liquefying the hydrogen has already been paid for, and transmission of hydrogen in a liquid form seems attractive. On the other hand, if the end-user only requires the hydrogen in a gaseous form, the transmission of liquid hydrogen might be of less interest.

The discussion above presupposes that the transmission system has not been combined with some other activity. A vapourization unit for liquid hydrogen acts as a heat sink and may be combined with an industry that uses refrigeration. Further, a combined transmission of hydrogen and electricity has been proposed in the "energy-pipe concept". In this case, liquid hydrogen is used for cooling a cryoresistive or superconducting electrical system which will follow the pipeline underground for the transmission of electrical energy.

Combined systems of the kind discussed above have no immediate future in Sweden, and in the following sections no such combinations will be taken into account.

7.2 Transmission of gaseous hydrogen in pipelines

7.2.1 Introduction

The amount of energy carried by a pipeline is governed by the flow rate of the gas, which depends on the pipe size and the pressure of the gas. The capacity is regulated by changing the gas pressure, up to the maximum permitted pressure. Pumps are not needed as the gas will move by itself towards those parts of the system where the pressure is low, i.e. towards the tap stations. Compressors are installed at regular intervals to keep up the pressure, and the capacity of a system is increased by the addition of larger compressors. The compressors require less than 0.1 % of the energy transported for a transmission distance of 100 km.

Leakages will invariably occur, and leak detection is part of the maintenance routine. Machinery with moving parts (compressors) has to be serviced regularly. A low leakage rate is admissible provided that the over-all system does not exhibit calculable losses of gas, cf 7.2.2.

7.2.2 Existing pipelines

A pipepline carrying hydrogen was built in the Ruhr, Germany, as early as in 1938 (1). The system has since then been enlarged by stages. The whole network including various distribution lines now comprises 208 km. The early network includes a pipeline of 300 mm nominal size and 14 km length, and another one of 200 mm nominal size and 9 km length, both laid as early as in 1938. Today more than 200 km of the line uses pipes with a nominal size larger than 100 mm, with a number of industries attached to the grid (1).

The pipes are designed for a pressure of 2.5 MPa, but in practice the pressure is kept at 1.5 MPa. Seamless pipes are used of German grade St 35, St 37 and St 29. The pipes are welded together, but the installed valves have flanged joints. The outer surface of the pipes is protected with a bitumen cover with a fibreglass wrap. A cathodic protection system has been installed. Pipes which have been used for 30 years have been examined and are still in good condition.

The pipeline traverses a number of towns, roads and waterways. It is buried 1 m below the ground, and a 10 m wide protective belt along the line is free from buildings. No special precautions have been taken, such as dilution of the hydrogen with an inert gas or transmission in double-walled pipes with hydrogen in the inner pipe and an inert gas at elevated pressure in the outer pipe. During the life of the grid, no explosions or hazardous situations have occurred, Figure 7-1.

The operation includes a monitoring system from a central control room. Data showing low rates and pressures are continuously surveyed, and remote-controlled valves may be used for directing the gas flow. The pipeline is surveyed monthly from a helicopter and inspected periodically by a linewalker, who looks at building activities near the line and any changes in vegetation. The gas contains enough impurities to have an odour, and leaks will thus be detected by their smell during this inspection.

During 1974, a total of 3.5 Gm^3 or 45 PJ of pure and crude hydrogen was handled in the system. The losses were within the limits of error of measurement, with a mass balance ranging from -1.44 % to + 0.92 % and a mean value of -0.28 %. This means that the actual losses are low and probably negligible.

The existence of this network and the fact that it has been in use for more than 40 years without any dramatic incidents proves that hydrogen can safely be transported in this way. However, special problems may arise when transporting pure hydrogen at high pressures, as is discussed in Chapter 13.

Other networks for hydrogen transmission have less capacity than the German one. A pipeline near Johannesburg in South Africa has a length of about 80 km, and another one in Kansas-Oklahoma, USA, of about 260 km uses pipes with a diameter of 50 mm, while the hydrogen pressure is about 12 MPa.

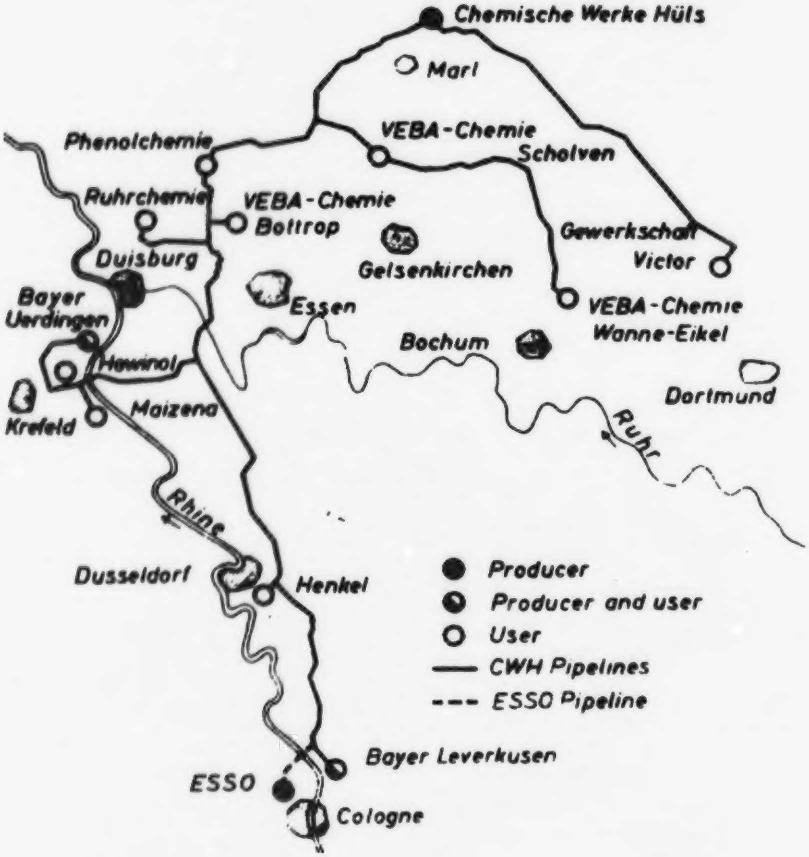

Chemische Werke Hüls
Marl
Phenolchemie
VEBA-Chemie
Scholven
Ruhrchemie
VEBA-Chemie
Bottrop
Gewerkschaft
Victor
Duisburg
Gelsenkirchen
Bayer
Uerdingen
Essen
VEBA-Chemie
Wanne-Eikel
Bochum
Hewinol
Dortmund
Krefeld
Maizena
Ruhr
Rhine
Producer
Producer and user
User
CWH Pipelines
ESSO Pipeline
Dusseldorf
Henkel
Bayer Leverkusen
ESSO
Cologne

Figure 7-1

Hydrogen transmission by pipeline in the Ruhr area, Germany.

7.2.3 Use of natural gas pipelines

Modern pipelines for natural gas have a diameter of 1200 mm and work at a pressure of 7 MPa. The direct use of natural gas pipelines for the transmission of hydrogen has been discussed, and it is of considerable interest in case of a shortage of natural gas. However, a natural gas system cannot be converted for hydrogen transport without certain modifications.

The capacity of a pipeline expressed as MJ/m^3 is not identical for the two gases. The combustion heat of 1 m^3 hydrogen is 12.77 MJ/m^3 at 0^oC, whereas natural gas has a value of 38.2 MJ. However, the density of hydrogen is about 1/9 of that of natural gas, and the quantity of gas transferred is proportional to the square root of this number, i.e. 1/3. This means that as a first approximation a given pipeline permits the transport of approximately the same amount of energy in the two cases. The above is valid at a pressure of 1 bar, but at higher pressures the capacity of a pipeline is lower for hydrogen. At a pressure of 50 bar, the capacity is lowered by about 10 % when hydrogen is introduced.

The energy needed for the compression of hydrogen is higher than for natural gas. In general, the compression of hydrogen leads to increased transport costs regardless of the technical state of the compressors. However, there are no large compressors for hydrogen available today, and no compressors have been built into existing pipelines. Material problems are to be anticipated as most often machine parts, such as springs, are made of high-strength steels which are susceptible to hydrogen. Development work should be foreseen in order to solve these technical problems.

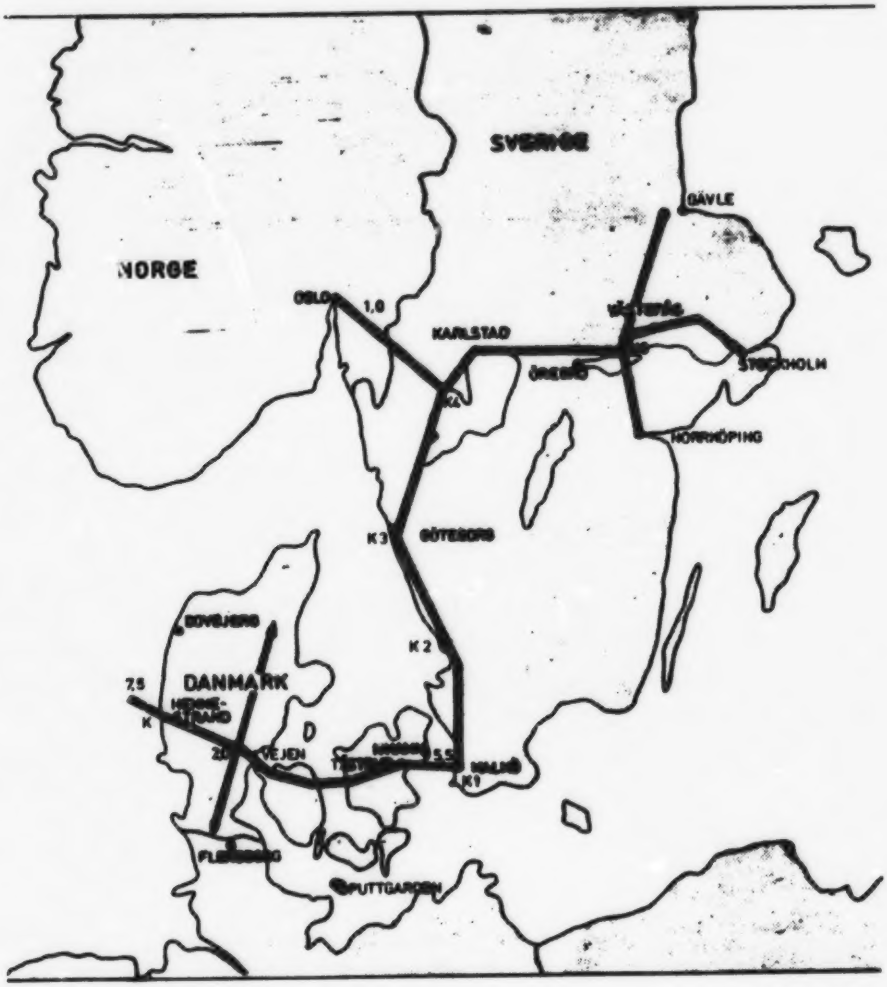
Voices have been raised in warning against hydrogen embrittlement and other mechanical effects on the piping material. A proper choice of materials is certainly important, as is discussed in Chapter 13. A pipeline for natural gas will be acceptable for hydrogen transport. However, leaks may cause additional trouble with hydrogen because of a higher leakage rate. The presence of defects such as cracks and wall thinning should be surveyed before a pipeline is converted to hydrogen transport. Such defects can be detected with modern instrumentation, where the detecting device, a "survey pig", travels inside the pipe for its entire length.

A study has to be made of the distribution equipment for natural gas and its possible use for hydrogen. These problems are studied in particular at the Institute of Gas Technology in Chicago, where loops have been operated with natural gas as well as hydrogen. Comparisons are made of flow rates, energy delivery, leakage rates and material compatibility (2).

Turning to the Swedish scene, AB Swedegas has made proposals to the Swedish government to build a natural gas network for deliveries in the south of the country to large consumers. Contracts for gas deliveries over a 20-year period are being discussed. After this time the network will be paid off and can be used for the delivery of natural gas or possibly other energy carriers. It will be possible to feed hydrogen in steadily increasing concentrations into the system. The whole network might ultimately carry hydrogen. One of the proposals for a Scandinavian network is shown in Figure 7-2.

7.3 Bulk transmission of gaseous hydrogen

The bulk transmission of large amounts of compressed hydrogen gas by lorry or by rail is possible, though the transport costs are high (7.6.2). Long experience of the delivery of hydrogen in bottles is available. According to Swedish standards, these bottles should have an outer diameter of 230 mm and a filling volume of 0.05 m^3. They are filled with hydrogen to a maximum pressure of 20 MPa, i.e. a content of about 10 m^3 of gas at normal pressure. As they should not be completely emptied before re-use and in addition there may be some loss during transfer operations, the content of one bottle approximates 0.1 GJ. A package of 10 bottles is easily handled by a fork-lift truck, 25 packages may be hauled by one lorry and 30 packages by a railway wagon. In this way hydrogen could be delivered to feed a local distribution network.


SVERIGE
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STOCKHOLM
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BOVBJERG
K 2
7,5
DANMARK
HEMME-STRAND
K
D
20
VEJEN
5,5
MALMÖ
K1
FLENSBURG
PUTTGARDEN

Figure 7-2

Proposal for a natural gas network in Scandinavia (3).

A single lorry can deliver 11000 GJ of gaseous hydrogen per year with a mean transport distance of 100 km. Comparing this with the pipeline network discussed in 7.2 and 7.6.2, 10^4 lorries are needed in order to meet the capacity of the pipeline. The load on the road network would be formidable and probably prohibitive.

Special tube trailers have been built in the US for the transport of hydrogen compressed to 40 MPa. One lorry can deliver 18 GJ, which is less than the amounts discussed above (4). This method of transport will not be possible unless the consumer has storage facilities for the gas. For a more general distribution scheme, it would be better to develop special containers which can deliver large gas bottles with a higher packing density than the standard bottles discussed above.

7.4 Transmission of liquid hydrogen in pipe lines

Today liquid hydrogen is used in large amounts in the US space program. For a moon mission, a Saturn 5 vehicle has to be loaded with about 1500 m^3 of liquid hydrogen. Thus the technology of handling and transmitting liquid hydrogen already exists, but distribution via pipelines has not taken place except within production facilities and short stretches at Cape Kennedy. A large-scale pipeline has yet to be built. Studies have been made and show that it is technically feasible to build one, but at costs which are certainly much higher than for gaseous transmission.

The main technical problems are those connected with the insulation of the line. Vacuum-jacketed constructions are commercially available and can be obtained also in T-sections, valves, etc. Thermal contact between the inner pipe and the outer jacket has to be avoided. The heat is transmitted by radiation, which can be minimized by inserting a number of reflective shields. A number of technical designs are available. Figure 7-3 shows a joint with the surrounding evacuated jacket. Refrigeration stations along the pipeline are needed in order to compensate for heat losses. Cryogenic pumps of all sizes are commercially available and should be adaptable to the pumping of liquid hydrogen. If possible, the pipeline should be located underground.

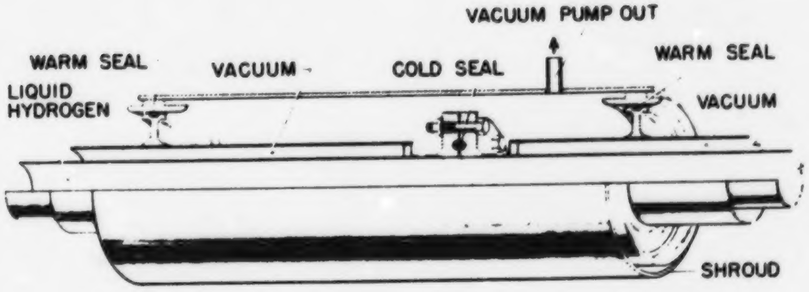

Figure 7-3

Design of the vacuum-jacket across a joint (6).

According to a new concept, the liquid hydrogen is cooled further to a mixture of solid and liquid phases. A slurry containing 50 % solids can be pumped in a pipeline, and the number of refrigeration stations along the line can be restricted. Further, the temperature is low enough to permit superconduction in Nb-Sn-alloys, which would lend support to the idea of combining the pipeline with an electrical transmission system (7).

At the present stage of technical knowledge, pipelines for liquid hydrogen seem feasible, but further development is needed for long distance transport. The concept is well worth further consideration, especially if liquid hydrogen becomes an attractive form for the storage of large quantities of hydrogen.

7.5 Bulk transmission of liquid hydrogen

In the US, the transport of liquid hydrogen has been carried out by lorry as well as by rail. Lorries can be used for quantities up to 60 m^3, while railroad tank cars have been built for up to 240 m^3. A container concept should be practical, as these can be handled by ships, railroads and lorries (4).

Tanks for liquid hydrogen have to be furnished with an evacuated insulation. Losses decrease with increasing volume. From experience they can be estimated to be less than 0.3 % per day for a 60 m^3 lorry (3, 8).

The presence of large tanks filled with liquid hydrogen on roads and railways calls for special safety measures. The tanks are fitted with safety valves and rupture disks. When hydrogen is vented through one of these devices an explosion-free concentration of hydrogen must be attained. This can be achieved by letting the vented hydrogen gas drive a gas motor, which operates a system for mixing the hydrogen with air to explosion-free proportions.

In general, there is a need for strict safety precautions, and the systems must be handled by trained personnel. The filling of one storage tank from another must be preceded by the removal of all contaminating gases (air) in the connecting lines; this should preferably be done by evacuation. If the receiving tanks have reached ambient temperature, large amounts of hydrogen will vapourize and this gas has to be taken care of. The tanking operations must not be finished until the connecting lines have been evacuated for the removal of hydrogen and subsequently filled with nitrogen or air. Similar precautions have been described in (8).

A biaxled railway wagon will carry 20 tons of cryogenic liquid according to current Swedish standards. Larger loads are permitted, but with the present tariff system they do not result in lower transmission costs. Liquid hydrogen in bulk quantities has not been freighted in Sweden to date, but international conventions valid from 1977 permit such transport in railway tank wagons in Europe.

Transport by lorry or tanker is subject to a similar convention which is not yet valid in Sweden, but the association is a formality. In practice, rules are available for the transportation of liquid hydrogen on roads as well as by rail. No formal or technical obstacles will restrict the transport in the future.

Modern railway tank trucks for liquid nitrogen are carefully insulated against heat losses and contain 63 m^3 of liquid. An equivalent tank truck for liquid hydrogen represents 600 GJ of energy. The arrival of one such truck per day would correspond to a theoretical transport capacity of 7 MW. Assuming that a single truck makes the round between the filling station and the producer and back again within 17 hours, a theoretical capacity of about 10 MW is obtained.

7.6 Costs of hydrogen transmission

7.6.1 General considerations

An equipment lifetime of 10 years is generally assumed, except for the pipeline systems where 20 years is assumed to be more appropriate for an investment return. With a real interest rate of 4 % and a straightline depreciation in equal annuities the corresponding capital recovery factors are 0.1233 (10 years) and 0.0737 (20 years), respectively. Taxes and profits are not taken into account.

7.6.2 Gaseous hydrogen transmitted by pipeline

AB Swedegas has recently studied the introduction of natural gas in Sweden, and AB Sydkraft has made a detailed calculation of the costs for a pipeline in western Skåne and southern Halland. The data are based on actual pipelines in western Europe and should be reliable. Many alternatives have been studied; figures for one basic alternative will be cited here (9).

The line will be able to deliver nearly 10^8 GJ/year and will transmit the gas over nearly 200 km, in pipes of diameter 600 mm and 250 mm. An investment of 308 Mcr is foreseen with annual costs for use and maintenance of 5 Mcr.

First, if this pipeline were used mainly for natural gas and hydrogen were introduced in increasing concentrations, this could be done with up to 15 % hydrogen without any changes in the system and with similar transport costs. Assuming a capital return in 20 years, the transmission of natural gas or hydrogen would cost 0.3 cr/GJ.

Second, if the natural gas pipeline were converted for the transport of pure or nearly pure hydrogen, changes would have to be made to the system. In particular, new compressor stations for hydrogen would be required and would call for investments; the size of these is not known today, but it would probably be large. Together with a general rejuvenation of the system, a new investment of the order of 200 Mcr (taking 1978 as the base year) is assumed with amortization over 10 years. The costs for use and maintenance will be 20 % higher than for natural gas, resulting in transmission costs of 0.4 cr/GJ.

Third, if a new pipeline is built exclusively for the transmission of hydrogen, an investment which is 1.6 times higher than for natural gas is assumed, i.e. 308 x 1.6 Mcr with reference to the system described above. Use and maintenance is estimated to be 6 Mcr yearly. The transmission costs will then amount to 0.5 cr/GJ with an amortization period of 20 years.

The schemes above presuppose a gas pressure of 8 MPa in the pipeline. Considering the good experience with long term transport at moderate pressures (see 7.2.1), it is of course possible to "play safe" and use a pressure of 2 - 3 MPa. The capacity would then be cut to roughly a third, and the transmission cost tripled, i.e. 1.2 cr/GJ. Since transmission costs of about 1 cr/GJ comprise only a few percent of the total price, it is undoubtedly possible to use a pipeline at moderate pressure.

A more general consumption of hydrogen, for e g household facilities and the heating of individual houses, will need a distribution network. The added costs have been studied in a report by the American Gas Association. The distribution will cost 60 - 70 % of the transmission (7), which means that a transmission cost of 0.3 - 0.5 cr/GJ results in distribution costs of 0.2 - 0.3 cr/GJ.

7.6.3 Bulk transmission of gaseous hydrogen

The transmission of compressed gas in packages of ten bottles was discussed in 7.3. Each package has a size of 1 x 1 x 2 m and weighs 800 kg. A single lorry with trailer can transport 25 of these packages, i.e. a total of 25 GJ. A railway car can move 30 packages at a time, i.e. 30 GJ.

The investment cost for one package is of the order of 5 kcr. During its lifetime of 10 years, it is used 500 times. As each package will deliver 1 GJ each time, roughly 12 cr/GJ in capital recovery has to be charged.

Assuming a mean hauling distance of 100 km, lorry and railway delivery will both cost about 40 cr/GJ according to present tariffs for commercial deliveries. A rough figure for the total transmission cost is thus 52 cr/GJ at a distance of 100 km; longer distances will give costs according to Figure 7-4.

Common commercial tariffs take into consideration the fact that vehicles are not normally loaded to full capacity and that a profit is included. Table 7-1 shows the order of magnitude of costs when vehicles are run with a full load and with no profits included.

Table 7-1

Costs connected with a single lorry transmitting 11000 GJ in a year, mean distance 100 km.

Capital costs	kcr/year
a) Truck, amort. time 3 years	81
b) Garages, offices, amort. time 20 years	15
Driver, incl. social security	72
Other personnel	18
Operating costs, incl. fuel, service, insurance	50
	236

According to Table 7-1 a non-profit tariff would be about 22 cr/GJ for a transmission distance of 100 km. Adding the capital costs for the packages, a total cost of 34 cr/GJ has to be taken into account. Longer distances are covered in Figure 7-4.

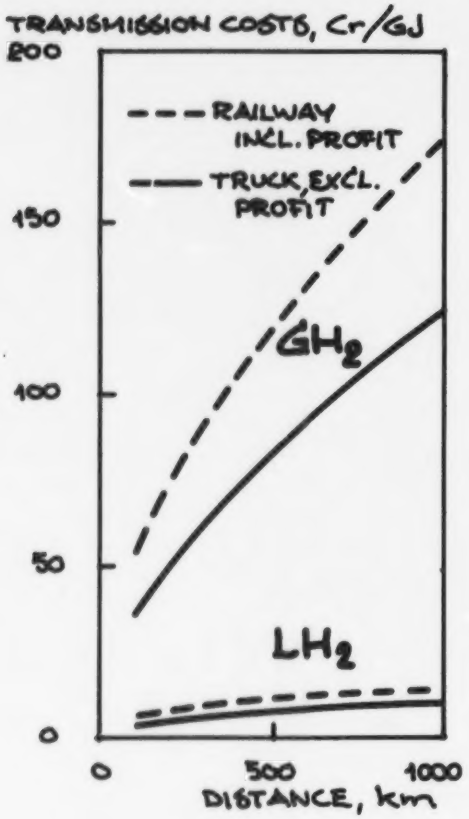

Figure 7-4

Bulk transmission costs.

The Swedish railway company, SJ, has designed up a special container wagon for gaseous hydrogen at a pressure of 3 MPa, which can deliver about 10 GJ. With an investment of about 200 kcr, this will not compete with the schemes described above.

7.6.4 Liquid hydrogen

Short pipelines for liquid hydrogen have been built, but cost figures are not available. All information about a pipeline system for cryogenic liquid transmission indicates that the costs today are much too high to encourage this method of transport.

The cost for liquefying hydrogen is assumed to be 10 cr/GJ. This price is not prohibitive for the transmission of liquid hydrogen in bulk, as the energy density is as high as 0.14 GJ/kg, which means that large amounts of energy can be transported in a single railway tank wagon or a tanker trailer.

Swedish price tariffs for the transport of liquid nitrogen, oxygen or hydrogen by railway tank wagon are at present 4.03 cr/100 kg (distance 100 km) plus a maximum of 100 % extra for dangerous freight. A maximum charge of only 355 kr is thus obtained for a wagon filled with about 60 m^3 of liquid hydrogen (4.4 ton, as the density is only 70 kg/m^3), which corresponds to 0.6 cr/GJ. As far as is known, this tariff has never been applied for liquid hydrogen, and it appears to be too low. The density of liquid nitrogen is 808 kg/m^3, and that of liquid oxygen is 1140 kg/m^3, which means much higher charges for a filled tank wagon. A price of 0.6 cr/GJ must therefore be regarded as the lower limit. A more realistic price based on volume should lie in the neighbourhood of 6 cr/GJ.

The loading and unloading of a railway tank wagon in connection with distribution to the consumer gives rise to extra charges, which together with the expense of converting the liquid to gaseous form are estimated to be about 1 cr/GJ. Distribution in small-sized pipes from an unloading station to the consumer amounts to an extra charge of about 1 cr/GJ, cf 7.6.2.

Road transport in container tanks is assumed to take place directly to the consumer. Using the same method of calculation as in 7.6.3 but allowing for higher costs for a container tank, transmission by lorry will cost 4.1 cr/GJ. A comparison with railway transmission is made in Table 7-2.

Table 7-2

Summary of costs assuming a mean transmission distance of 100 km.

	Railway cr/GJ	Lorry cr/GJ
Transmission	0.6-6	
		4.1
Distribution	2	
	2.6-8	4.1

The upper price limit for railway transmission will most probably be nearer to the true costs than the lower limit. In Figure 7-4, cost of 6 cr/GJ has been assumed for a transmission distance of 100 km; other distances have been plotted according to the current tariffs.

As regards the capacity of bulk transport of liquid hydrogen, consider the theoretical amount of energy transported by a lorry containing 20 m^3 of cryogenic liquid. One load corresponds to about 200 GJ, and the arrival of one lorry each day to a power station corresponds to a mean power of 2.3 MW if the hydrogen is burnt with 100 % efficiency.

7.6.5 Summary of costs and investments

The costs for transmission and distribution as detailed in 7.6.2 - 7.6.4 are listed in Table 7-3, omitting taxes and profits. Not surprisingly, gas transmission by pipeline gives the lowest end price, but bulk transmission of the liquid is also acceptable.

The cost estimations have been restricted to a transmission distance of 100 km, or for pipeline transmission to a 200 km line. In the latter case, transmission costs decrease with increasing distances because of certain fixed costs and the benefit of building and handling a larger system. In the case of bulk transmission, capital costs increase with increasing distance because of lowered capacity and higher freight costs.

Investment requirements are given in Table 7-4. The investments for the transport of liquid hydrogen are surprisingly low, and the transport capacity can also be built up from moderate to high without difficulty. Very high capacities are probably not achievable because of restrictions on road and railway traffic. In principle, only 240 railway vehicles are needed to handle the equivalent of a pipeline capacity of 1.35 GW. However, higher labour and maintenance costs make liquid transmission somewhat more expensive than by pipeline (Table 7-3).

Table 7-3

Costs of hydrogen transmission and distribution for various transport modes. A distance of 200 km is assumed for transmission by pipeline, and 100 km for all other cases.

	Costs in cr/GJ (1978)		
	Transmission	Distribution	Total
Gaseous hydrogen by pipeline	0.4-1.2	0.2-0.3	0.6-1.5
Gaseous hydrogen in bulk by lorry	34	*)	34
Liquid hydrogen in bulk by lorry	4.1	*)	4.1
Liquid hydrogen in bulk by railway	0.6-6	2	2.6-8

*) Distribution costs are included in the transmission costs.

Table 7-4

Investments and capacities for various transmission modes. The numbers for bulk transmission are related to 100 lorries in operation.

Transport mode	Mean capacity life PJ/year	Capacity during lifetime PJ	Mean power Total MW	Investment	
				Mcr	cr/GJ/year
GH_2 in new pipeline	76	1520	2410	493	6.5
GH_2 in bulk by lorry	1.1	3.3	4.0	25	22.7
LH_2 in bulk by lorry	8.8	26	280	60	6.8

7.7 Comparison with other energy carriers

7.7.1 Electricity

Today, the transmission of electricity is accomplished by means of 400 kV power lines above ground. The actual prices charged by the Swedish authorities are based on a maximum power of 650 MW and result in an annual long-distance transmission cost of 52 cr per MW and km. In a hydrogen economy, such large amounts of energy can only be transmitted as hydrogen gas by pipeline (the 2410 MW case of Table 7-4). However, in addition to pure transmission costs, account must also be taken of the extra costs connected with the transformation from 400 kV to 400 V before feeding the energy into the customers' network. These extra costs are high and comprise 200 cr/kW per annum. The total transmission costs are therefore 8.1 cr/GJ for a distance of 200 km. Table 7-5 and Figure 7-5 show the influence of transmission distance.

Table 7-5

Transmission cost of electricity as a function of distance, c.f. Figure 7-5.

Distance, km	Transmission cost, cr/GJ
100	7.2
200	8.1
500	10.8
1000	15.2

7.7.2 Methanol

Transmission by lorry has been covered in 7.6.4 in the case of liquid hydrogen. The same calculation method has been used for methanol, in which case the costs for the container lorry and handling will be lower. Assuming that the costs for the lorry service are reduced by 10 %, each lorry delivering 18000 m^3/year at a transmission distance of 100 km costs 321 kcr/year. This means a transmission cost of approximately 1.0 cr/GJ.

7.7.3 Petrol and oil

The transmission costs for petrol and oil are calculated by comparision with methanol (7.8.2) after due correction for differences in energy density. At a distance of 100 km, the transmission costs are 0.51 cr/GJ for petrol, and 0.45 cr/GJ for oil. Costs at longer distances are plotted in Figure 7-5.

7.8 Safety aspects

7.8.1 Transmission of gaseous hydrogen by pipeline

Large pipelines have been operated for decades with few incidents, as described in 7.2.1. Regular surveyance makes the operation safe, and no special difficulties are foreseen.

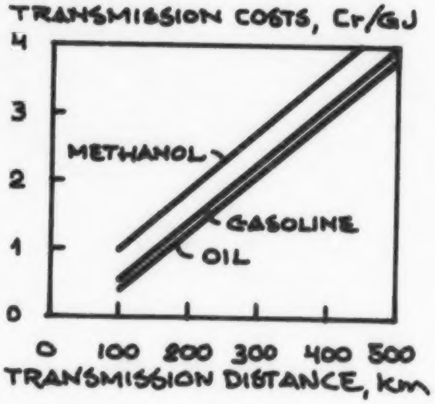

Figure 7-5

Bulk transmission costs of methanol, petrol and oil.

Smaller lines, such as distribution lines within urban areas, will cause more trouble than the larger ones. Damages to the lines may be caused by digging in the ground in connection with service to water/sewage pipes or electric cables. Digging is today seldom or never done by hand, and the machinery used will easily damage a steel pipe and fracture a plastic tube. Sparks are created and might ignite escaping hydrogen. Leaking gas will rapidly permeate the soil, and the "invisible" flame will hardly be seen in daylight. As a safeguard, it should be possible to bury a brightly coloured plastic strip 0.1 - 0.2 m above the pipeline as an indication of the underlaying pipe. Similar protective measures are taken today in order to avoid damage to underground electric cables.

Leakage in a gas system above ground will certainly call for a leak detection system. Odourants in the form of sulphur compounds should work satisfactorily. It has been discussed whether illuminants should also be introduced, so as to make the flame visible.

A proper choice of pipeline steel and good welding practices are always needed for safety reasons. An ordinary pipeline steel may develop cracks which propagate beyond a weld because of structural similarities of weld and pipe. The speed of crack propagation may easily exceed the rate at which the gas pressure is lowered by gas loss through the crack, in which case the crack may continue to run many kilometers. Such catastrophic ruptures of a pipeline have occurred (10).

7.8.2 Bulk transmission of hydrogen

A large fleet of railway wagons and lorries is needed for the bulk transmission of hydrogen. Regardless of whether the hydrogen is gaseous or liquid, the safety problems are principally connected with traffic accidents. These risks are covered in the regulations for the transport of hazardous materials.

Special precautions must be taken when handling liquid hydrogen during filling operations. The temperature is low enough to liquefy air in transfer lines. A line to be filled with hydrogen must be purged with an inert gas. Otherwise the liquefied air will become enriched with oxygen. In combination with flammable materials, fires may easily develop. All flammable materials must be avoided in the vicinity of installations for liquid hydrogen. Trained personnel should handle the system.

7.9 Conclusions

Large amounts of hydrogen gas is preferably transmitted by pipeline. Transmission over a distance of 200 km with a power output of 2.4 GW costs only 1 cr/GJ even if conservative pressures are chosen, which is still a low figure compared to other modes of transmission. However, investments are high, 200 Mcr/GW, and the line has to be dimensioned so that it will be large enough for future peak demands. The capital costs will thus raise the initial transmission costs unless the full capacity can be utilized. However, the transmission costs are moderate.

Liquid hydrogen can be transmitted by road or rail. The investment is proportional to the power demand, so that the investment level can be limited in the initial stages. However, this mode is limited by access to roads and railways, as the transmission of quantities equivalent to the capacity of pipelines necessitates a fleet of 1000 large lorries or a slightly smaller number of railway wagons.

The transmission costs for LH_2 are many times higher than for GH_2, Table 7-6. The table also compares transmission costs for alternative energy carriers as a function of transmission distance.

Table 7-6

Transmission costs of alternative energy carriers in cr/GJ

	Distance, km		
	100	200	500
GH_2 (pipeline)	0.6	1	2.4
LH_2 (bulk)	5	7	11
NG (pipeline)	0.4	0.7	1.3
Methanol	1	1.8	4.6
Petrol	0.5	1.4	4
Electricity	7	8	11

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8. CHEMICAL INDUSTRY

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8.1 The global use of hydrogen

Well over 95 % of the global consumption of hydrogen is supplied in the form of more or less hydrogen rich gas mixes. Other main components of these gases are hydrocarbons, carbon oxides, oxygen and nitrogen. A major part of these gas mixtures is consumed by a few of the chemical process industries, such as the basic chemical industry (mainly ammonia and methanol synthesis), the petroleum refining industry (desulphurizing, cracking, visbreaking etc and as internal refinery fuel) and by the iron and non-ferrous metal industries.

Some 2 - 3 % of the total hydrogen used is consumed in a pure form and is currently derived by the electrolytic decomposition of water. Far from all of the pure hydrogen is manufactured by electrolysis with the sole purpose of deriving only this substance. A significant fraction is extracted as a by-product in the chlorine/alkali and chlorates industries for use mainly in the basic chemical industry as a reducing agent.

An estimate of the 1978 world use of hydrogen would read:

	Approx.* production M tons	Hydrogen consumption M tons
Ammonia	70	14
Methanol	9	1.3
Oil refining	3000	12.5**
Metallurgy	-	1.2
Other uses		1 (mainly in pure form)
		30

* Sources: UN/ECE: Market trends for chemical products 1970 - 75 and prospects for 1980.

** Very rough assessment. A large, maybe even a major part, is used as refinery fuel.

8.2 Present use of hydrogen in the chemical process industries

Hydrogen currently has a very limited use in the Swedish process industries as a raw material or as fuel. Consumption within the following industries can thus be ignored.

	Note
- Iron and steel industry	Low-grade hydrogen in blast furnace waste gases used only for heating purposes
- Ferro-alloy industry	
- Primary metal industries	Only aluminium, copper, lead and some noble metals are produced domestically in minor amounts
- Pulp and paper industry	

- Silicate industries	Cement, lime, brick, concrete, china, glass and glass wool industries
- Food industry	Hydrogen used only for the hardening of fats (marginal quantity)

As is apparent from Table 8-1, hydrogen is also consumed to a rather limited extent in the chemical process industries. Thus only about 0.2 Mtons of hydrogen are used in the industries referred to in the table, with less than 20 % used as raw material in chemical conversion. Over 90 % of the feedstock hydrogen is produced either by gasification of fuel oil (ammonia synthesis) or as hydrogen rich by-product streams in refinery operations. Less than 10 % of the hydrogen is extracted at a purity better than 99 % in the chlorine/alkali and chlorates industries. Foreign trade with hydrogen as such or in the form of hydrides is negligible.

Table 8-1

Hydrogen consumption in Sweden 1978.

	Consumption 1000 tons/year	
	Raw material	Fuel
Chemical industry proper	24.7	5
organic chemical industry	1.7	-
inorganic chemical industry		
synthesis of NH_3	22	-
production of HCl*	1	5
Petroleum refining	10	160
Food industry (hardening of fats)	0.3	-
Overall use	35	165

* By-product hydrogen from chlorine/alkali industries.

Would this limited consumption have been signigicantly larger in these industries if the users had had access to hydrogen supplied by means of a pipe transmission system? The answer is a firm no and can be directly related to the high cost of electrically derived hydrogen in relation to competing fuels (a cost factor of 2 - 8). Such a cost level would have been prohibitive for any use of hydrogen except as a raw material for chemical conversion (reduction) in the organic chemical industry and in the food industry (hardening of fats). Even if consumption for these purposes had been doubled or quadrupled, it would still have been very marginal. The major consumers (the refineries) as a rule have a surplus amount of hydrogen in their production system since gas streams containing hydrogen are virtually unavoidable by-products in refining operations. Thus the overwhelming share of these gas streams is used as first class fuel in common pipe-still furnaces or for steam raising. Only in refineries where desulphurizing of products and/or visbreaking are excessive operations can the major part of the hydrogen rich gases find a qualified outlet for the up-grading of products.

The following factors seem to be decisive for the future consumption of hydrogen in the Swedish chemical process industries:

- The price of hydrogen in relation to the price of competing raw materials and energy products.
- The rate of drain of gas and oil reserves and consequently the development of the refinery industry.
- New hydrogen based chemical production.

8.3 Price trends 1978 - 2025

It goes without saying that it is almost impossible to predict the rate of price movements over a 50-year period. In Tables 8-2 and 8-3 various assumptions have been made about the average annual rate of increase in real terms for the energy products under consideration. These rates have been distributed over the three periods 1978 - 1985, 1985 - 2005 and 2005 - 2025.

The assumptions underlying Table 8-2 are based on the numerous speculations and estimates that have appeared in the five years following the 1974 energy crisis. This table is therefore to be regarded as a maximum price growth alternative. A provision for the price scenario outlined is that the relatively fast global growth of Gross National Product (GNP) will continue well into the coming century. The shortage of oil and natural gas will be acute at the turn of the century and cause a very rapid price increase for these energy products. The development and use of alternative energy sources such as nuclear production systems will thus be enhanced. Breeder technology will become an important factor as early as in the first decades of the coming century and will be followed by nuclear fusion power.

According to this price scenario the competitive position of hydrogen in relation to oil and natural gas will increase significantly during the latter two decades of the period. This is mainly a consequence of the assumption that a break-through in the technology and use of breeder reactors will take place around the turn of the century.

By comparison Table 8-3 depicts the price scenario chosen for this study. A basic provision is a low-growth global GNP leading to a reduced energy demand and a slower depletion of oil and gas reserves. Real price rises for the energy products will be far less dramatic than those shown in the scenario given in Table 8-2.

The development of a new and more economic technology for the generation of hydrogen will also contribute to the improved competitive position of hydrogen. On the other hand, the development that is projected implies that nuclear based electrical energy remains competitive vis-a-vis hydrogen and actually improves its position compared to other energy products.

The milder price escalation depicted in Table 8-3 obviously gives similar results with respect to the competitive positions of the various energy products. Thus in some 40 years' time hydrogen would seem to be quite competitive in relation to the liquid motor fuels.

Table 8-2

Real price growth of energy carriers 1978 - 2025 (1978 price level).

Energy carrier	1978		Real price increase 1978 - 1985 %/year	1985	Real price increase 1985 - 2005 %/year	2005	Real price increase 2005 - 2025 %/year	2025
	cr/ton	cr/GJ		cr/GJ		cr/GJ		cr/GJ
Coal	180	6.2	2	7.1	3	13	3	23
Steam coal	280	9.6	2	11.0	3	20	3	35
Coke	380	13.6	2	15.5	3	28	3	52
Crude oil and heavy fuel oil	380	9.4	2	10.8	4.5	26	6	85
Petrol	700	16.7	2	19.2	4.5	46	6	150
Synth. petrol	1250	30	2	34.5	3	62	3	110
Natural gas (NG)		10.5	2	12.0	5	32	5	85
Synth. NG (SNG)		22	2	25.3	3	45	3	85
Methanol (from NG etc)	600	26.4	2	30.3	3.5	60	3.5	120
GH_2 (electrolysis)	(5800)	(40.7)	2	47.0	3.5	93	2	140
GH_2 (from NG)	(2750)	(19.3)	2	22.0	4	48	4	105
LH_2 (electrolysis)	(7150)	(50.0)	2	57.5	3.5	114	2	165
Electricity (nuclear)	0.10/kWh	27.8	2	31.9	4	70	2	105
Electricity (oil/coal)	0.15/kWh	41.7	2	47.9	3.5	95	3	170

GH_2 = Gaseous hydrogen

LH_2 = Liquid hydrogen

Table 8-3

Real price growth of energy carriers 1978 - 2025 (1978 price level).

	1978 cr/GJ	Real price increase 1978 - 1985 %/year	1985 cr/GJ	Real price increase 1985 - 2005 %/year	2005 cr/GJ	Real price increase 2005 - 2025 %/year	2025 cr/GJ
Coal	6.2	1.1	6.7	2	10	1.9	15
Steam coal	9.6	1.1	10.3	2	15.5	1.9	23
Coke	13.6	1.1	14.8	2	22	1.9	32
Crude oil	11.0	1.9	12.6	2.8	22	2.2	34
Petrol	19.5	1.9	22.2	2.6	37	2.6	61
Synth. petrol	35	1.5	39	1.5	51	1.0	62
Natural gas, NG	10.5	1.9	12	3.3	23	2.5	38
Synthetic NG	14.2	1.4	15.7	2.1	24	1.8	34
Methanol (IEA)	26.4	2.3	30.9	3.0	56	2.6	94
Methanol (import)	26.5	1.8	30	1.8	43	0.9	52
Methanol (from biomaterials)	-	-	55	0.2	58	0.2	60
GH_2 (electrolysis)	-	-	42.5	0.8	51	1.0	62
GH_2 (steam reformed NG)	17.7	1.5	19.6	2.8	34	2.5	55
GH_2 (coal gasification)	25.3	-1.7	22.3	1.1	27.5	1.2	35
LH_2 (electrolysis)	-	-	52.9	1.0	65	1.0	80
Electricity (nuclear)	24.4	1.7	28	1.7	39	1.7	54
Electricity (from oil/coal)	40	1.7	45	1.9	65	1.9	95

Table 8-4

The oil refinery industry 1975 - 1980.

	Density	Percentage		Product		Notes
	tons/m^3	by volume	by weight	1000 Nm^3	1000 tons	
Product mix						
Refinery gases*	0.5(liq)	4.2	2.5	760	380**	To desulphurization and fuel (internal refinery use)
LPG	0.58	0.6	0.4	110	65	
Naphta	0.71	1.4	1.1	260	185	Feedstock, petrochemical industry
Petrol	0.72	17.0	14.3	3060	2200	
Aviation kerosene	0.78	2.2	2.1	400	310	
Other kerosene	0.78	0.2	0.2	40	30	
GO	0.815	31.3	31.0	5625	4600	
HFO + VGO + asphalt	0.94	42.3	48.0	7600	7150	
Flaring, evaporation losses	(0.55) (liq)	0.8	0.4	145	80	
		100	100	18000	15000	

LPG = Liquid petroleum gas

GO = Gas oil (light fuel oil + Diesel fuel)

HFO = Heavy fuel oil

VGO = Vacuum gas oil

* Incl. hydrogen rich reformer gas.

** Containing an estimated amount of hydrogen of about 155000 tons.

Table 8-5

Refinery industry development 1980 - 2025.

		1980	1985	2005	2025
Refining capacity	Mtons	21	23	20	10
Production	"	15	20	16	8
Refining gases	GNm^3	0.75	1.05	1.00	0.50
"	Mtons	0.37	0.53	0.50	0.25
Light products	Mtons	2.7	4.3	4.5	3.0
GO	"	4.6	6.9	5.5	2.4
HFO + VGO	"	7.3	8.1	5.4	2.3
Use of refinery gas (RG) for desulphurizing					
Light products + GO	RG, Mtons	0.005	0.01	0.01	0.006
HFO + VGO to desulph.	Mtons	1.0	2.5	3.5	1.5
HFO + VGO	RG, Mtons	0.005	0.01	0.02	0.014
Total, desulph.	"	0.01	0.02	0.03	0.02
Energy use in refinery					
- Refinery gases	Mtons	0.36	0.51	0.47	0.23
- Fuel oil	"	0.29	0.24	0.13	0.07
Energy use, total		0.65	0.75	0.60	0.30
Maximum possible use of pipeline gas (NG or H_2)					
NG/H_2	GNm^3 NG	(0.35)	0.28	0.15	0.08
NG/H_2	PJ	(13)	11	6	3

- Average contents of S in GO anticipated for 1980 = 0.3 %, for 1990 = 0.2 %.
- Average contents of S in HFO anticipated for 1985 = 1 %, for 1990 = 0.7 % and for 2000 = 0.4 %.
- Desulphurizing of HFO has been calculated on the assumption that all such processing is performed by means of VGO reduction from 1.9 % to 0.2 % S followed by mixing with non-desulphurized HFO (hydrogen consumption about 50 MNm^3 per Mton VGO).

GO = Gas oil (light fuel oil + Diesel fuel)
HFO = Heavy fuel oil
VGO = Vacuum gas oil
NG = Natural gas
RG = Refinery gases

8.4 Potential applications and trends

8.4.1 Oil resources and development of the refinery industry

The reserves of oil and natural gas will no doubt continually be reduced during the period under review. Price escalation will thus be greater for these energy products than can be expected for possible alternatives. Refined petroleum products, imported to the main western consumers from production plants close to the sites of exploitation, will replace imports of crude oil to a growing extent. The refinery industry in Western Europe will have to be curbed before the end of this century, which implies that the present dependence on crude oil will be transformed into a dependence on refined products. This development would mean that the Swedish refining industry will most probably reach its maximum production shortly before the turn of the century. By the end of the period under review, production might even have fallen to a level of some 50 % of the present one, as shown in Tables 8-4 and 8-5. While progressively stringent environmental requirements are certain to claim significant quantities of hydrogen in the refineries for the desulphurizing of products and waste gases, there would seem to be adequate by-product hydrogen to make externally generated hydrogen superfluous. On the other hand part of the by-product hydrogen may under certain circumstances find a qualified use outside the refinery sector.

8.4.2 New chemical production based on hydrogen

To make a projection for the time beyond the turn of the century is a delicate task. For the period up to that point it is, however, probable that a slightly reduced hydrogen price in relation to competing energy products, as indicated by the Tables 8-2 and 8-3, would have no more than a marginal effect.

8.4.2.1 Chlorine/alkali

The chlorine/alkali industry is expected to show a slightly decreasing trend, possibly compensated for by a steady increase of the smaller chlorate industry. By-product hydrogen from these industries may fall off if a cathode, depolarized by means of air or oxygen, is developed and commercialized during the next two decades. In general it seems wise to assume an unchanged consumption of by-product hydrogen from these industries for use in chemical conversion as well as for heating purposes.

8.4.2.2 Ammonia

Domestic demand for ammonia has increased steadily although at a slow annual rate. From the level of ten years ago, namely c. 215000 tons, the current consumption exceeds 250000 tons with some 50 % covered by imports of liquid ammonia from Norway, Holland and Western Germany. Of this consumption circa three quarters ends up as fertilizer products, with a predominant part passing through the nitric acid stage (N, NP and PKN-agrofertilizers), and a minor part in the form of urea is used as a forest fertilizer. About one fourth of the ammonia is consumed for technical purposes, e.g. as urea for condensation plastics, as ammonium nitrate for explosives and for various chemicals.

The slow annual increase in the demand for ammonia, which averaged 1.5 to 2 % during the 1968 - 78 period, is expected to continue at this rate. In common with many other industrialized countries, the Swedish agriculture has reached an optimum fertilizing level, and the cultivated area is slowly diminshing. There is still room for an extended nitrogen fertilization of the forested area, but unless hitherto unproductive areas are subjected to large scale plantation for the growth of energy biomass no spectacular increase of the nitrogen fertilizer is to be expected. Should such large scale plantation be ecologically feasible, it will probably not occur within the next five to ten years. With technical nitrogen outlets expected to show an increase of circa 4 % per year in the next ten years, it seems reasonable to assume an annual 1 - 2 % growth in the demand for ammonia.

The Swedish production of ammonia has been handicapped for a long time by the large scale of foreign production. To remain competitive the two existing Swedish plants, with current capacities of 55000 tpa and 65000 tpa, respectively, ought to be concentrated into a single plant with some three times the combined present capacity. Since ammonia and its derivatives, such as nitrogen fertilizers and explosives, can hardly be replaced in agriculture and defence, existing plants will probably be retained for some time to come even though they may prove uncompetitive. Heavy fuel oil and waste oils are currently utilized as feedstock. The prospects of an exploitation of important uranium-bearing shale deposits in the southern part of the country may influence a future capacity increase as will be explained in 8.4.3.

8.4.2.3 Methanol

Methanol demand has grown considerably faster than the demand for ammonia. With an average annual increase of 9 % in the ten year period 1968 - 78, the demand at present is 125000 tons. Some 75 - 80 % of this quantity is consumed in the conversion of methanol into formaldehyde. The remaining part of the methanol is consumed predominantly for solvent purposes. The use of methanol for chemical conversion, e.g. esterification, is limited.

Even though it seems probable that the future demand for methanol for conversion into formaldehyde will continue to increase by circa 4 % a year, it seems obvious that its use for chemicals may be outdistanced by new user applications such as the addition of methanol and methanol derivatives in petrol mixes. A five to ten times larger domestic methanol market may be opened up by fairly recently initiated and current R & D acitivies.

As regards the economic factor of scale, the conditions are identical with those for ammonia. Synthetic methanol has never been produced in the country. Following present interest in the use of mehthanol in motor fuels, construction of a pilot plant is, however, under consideration. Waste material from forestry, e.g. bark, stumps, branches as well as other bio-material such as peat and "energy" trees, are under review as feedstocks for this production. For a full size plant, it seems, however, that a large scale exploitation either of shale deposits or of peat bogs would be necessary.

Although it is true that future methanol plants could bring about a significant expansion in the use of hydrogen*, this market would hardly be open to electrolytic hydrogen supplied by pipeline. The reactors have to be fed with a gas mixture close to $2H_2 + CO$. As a rule, and for reasons of cost, a feed gas of the right composition is co-generated in a preceding gasification process from a feedstock containing carbon, fossil fuel, organic waste or other organic material.

Ammonia plants equipped with air fractionators might possibly benefit from a hydrogen pipeline service. It seems more likely, however, that ammonia and methanol plants, if they are ever built, would inspire the introduction of local or regional pipeline systems for the transport of energy gas from jumbo gasification plants (or alternatively from a series of smaller standard size gasification plants connected to the grid); these pipelines would then also supply the ammonia/methanol plants.

8.4.2.4 Other chemicals

Other chemical uses of hydrogen (normally in the form of pure gas) fall under the category of organic synthesis/reduction. As a rule they concern small quantities of special chemicals, as in the reduction of nitro compounds, saturation of double bonds in organic compounds and reduction of alcohols and aldehydes. With the exception of a possible development of metal hydrides suitable for energy storage in motor or fuel cell powered vehicles, no areas are readily discernible where hydrogen can be used within the inorganic field**.

8.4.3 Uranium bearing shales - a Swedish quandary

As was mentioned earlier, a profitable exploitation of shale will play a key role in the not too distant future, not only in solving the serious Swedish energy problem, but also for developing the ammonia and methanol production of the major hydrogen consuming industries.

The shale deposits are possible sources of energy (uranium and kerogen), of chemicals (aluminium sulphate, potassium salts) and of primary metals (e.g. vanadium, molybdenum and cobalt). On account of the relatively high content of organic substance (kerogen), shale may also serve as a secondary source of hydrogen.

The gasification process can be controlled and directed towards the production of energy or feedstock gases of various compositions:

I. Oxygen gasification - steam conversion (hydrogen)

$$C_nH_m(O,N,S)_\gamma + \frac{n}{2} \cdot O_2 \longrightarrow nCO + \frac{m}{2}H_2 + \left[\gamma H_2S + \frac{\gamma}{2}N_2\right]\downarrow \longrightarrow$$

$$\xrightarrow{+\ nH_2O} \left[n \cdot CO_2\right]\downarrow + \left(\frac{m}{2} + n\right) \cdot H_2$$

---

* A 0.55 million tons per year methanol plant ought to consume circa 0.07 - 0.08 million tons of hydrogen.

** The possible use of hydrogen in the direct reduction of metal raw materials, e.g. oxide and silicate ores, is treated in Chapter 9 of this report.

II. Oxygen gasification - partial steam conversion (methanol)

Resulting gas: $\left[k \cdot CO_2\right]\downarrow + \; n-k \; \cdot CO + \left(\frac{m}{2} + k\right) \cdot H_2$

Since the ratio H_2: CO should be close to 2 in a gas mixture suitable for methanol conversion:

$$\frac{m + 2\ k}{2(n-k)} = 2$$

$$m + 6\ k = 4\ n$$

Assuming an average ratio of H:C = 2 in kerogen, i.e. $m = 2\ n$

$$6\ k = 2\ n, \quad k = 1/3\ n$$

Thus the resulting gas = $2/3\ n\ CO + 4/3\ n\ H_2$ or

$$CO + 2H_2$$

III. Air gasification - steam conversion (ammonia)

Resulting gas: $\left[n \cdot CO_2\right] \; + \left(\frac{m}{2} + n\right) \cdot H_2 + k \cdot N_2$

As $H_2:N_2$ should be close to 3 in a gas mixture suitable for ammonia conversion

$$\frac{m + 2\ n}{2 \cdot k} = 3$$

$$m + 2\ n = 6\ k \qquad\qquad m = 2\ n \text{ (see II)}$$

$$k = 2/3\ n$$

Since the molar ratio $N_2:O_2$ in air is close to 4.6, i.e.

$$k: \frac{n}{2} = 4.6 \quad \text{or} \quad k = 2.3\ n$$

it is necessary to enrich the air with oxygen before gasifying to an $N_2:O_2$ molar ratio of circa 1.33. If hydrogen can be delivered to the plant at an attractive price, it would clearly be possible to raise the hydrogen content by means of direct feeding of hydrogen into the gas mix, thereby avoiding the air fractionating plant.

In a similar manner peat and other bio-material can be used as secondary sources of hydrogen.

Unfortunately, the important Swedish energy resources locked up in shale deposits are at present unavailable for environmental reasons. A local veto as well as strong public movements are firmly blocking all exploitation activity.

8.5 Future use of hydrogen in some chemical processing industries

The basic conditions for the hydrogen study have been defined in the form of three general scenarios:

Scenario A Energy supply mainly secured by means of nuclear generation of the type commonly in use, i.e. ordinary non-breeder fission reactors.

Hydrogen will be produced by electrolysis or in thermo-chemical processes. Electricity will be the major competitor of hydrogen.

Scenario B Energy supply to a large extent by renewable sources, i.e. solar power (direct solar heat and electricity generation, wind, wave and bio-materials energy).

Hydrogen will be produced by chemical, photochemical or biochemical conversion as well as by electrolysis. Major competing energy carriers will be methane, methanol, ethyl alcohol and "bio-fuels".

Scenario C Energy supply by means of NG and imported synthetic fuels, the latter produced from coal.

Main hydrogen competitors will be synthetic petrol and SNG.

A continuously expanding pipeline system will cover large parts of the main energy consuming regions of the country. The grid will be fed initially by imported NG and later by imported and/or domestically generated SNG.

It is to be expected that each of these three different supply scenarios would bring about somewhat different price developments in a time span of close to 50 years. However, it has not been possible to assess the different price trends relating to each scenario. A common price development according to Table 8-3 has therefore been postulated.

8.5.1 Demand for hydrogen as a feedstock

Table 8-6 sketches a possible evolution in the demand for hydrogen for the coming 50-year period. The figures have been assessed taking into consideration the premises discussed above. The proposed consumption applies only to qualified uses such as chemical raw material and excludes surplus hydrogen consumed as fuel.

Table 8-6

Possible use of hydrogen as a feedstock in the chemical process industries 1980 - 2025, 1000 tons per year.

	1985	2005	2025
Hardening of fats and oils	0.4	0.8	1
Chemical reduction	(7.5)	(12)	(20)
Muriatic acid (by-product of H_2)	(1.1)	(1.5)	(2)
Ammonia synthesis	(25)	(0*-40**)	(0*-50**)
Methanol conversion	(0*-30**)	(0*-125**)	(0*-125**)
Other chemical industries	-	-	-
Petroleum refining	20	30	20
Overall consumption	54 - 84	44 - 209	43 - 218
" , PJ/year	7.7 - 12	6.3 - 30	6.1 - 31
of which possibly pipeline gas PJ/year	-	0 - 1	1 - 3

* Provided that an open, non-protected economy is adopted as the future national policy.

** Provided that future policy contains a strong element of stimulus and/or protection. Another likely provision is the opening up of the shale deposits for exploitation.

Note: Figures within brackets indicate that the hydrogen will most likely be generated locally in close proximity to the site of consumption. Pure hydrogen generated externally is unlikely for the purpose.

Scenarios A and B

It seems evident that the overall consumption of pure hydrogen as a raw material in the chemical process industries is not likely to increase significantly. If special economic conditions are created for the ammonia and methanol industries the use of hydrogen in gas mixtures could surpass 0.2 million tonnes (25 PJ) in about 25 years' time. The major share of such a consumption might, however, be made up of gases that contain hydrogen which are generated close to the user plants. Part of this gas may be supplied by means of local or regional pipelines. Each one of these grids would most likely be fed by one or more gas generators producing gas mixes satisfying feedstock specifications as well as fuel gas requirements.

Such a system may be boosted by electrolytic or other hydrogen generators to compensate for variations of load and of gas composition.

Scenario C

The higher figures in Table 8-6 may be considered as being more likely under the conditions assumed for scenario C. The pipe grid for NG/SNG/H_2 would constitute a favourable pre-requisite for ammonia/methanol plants and ought to allow for domestic generation of these products. This would apply particularly towards the latter part of the period under review, when gasification plants based on bio-materials have been phased into the supply system. It is, however, less likely that pure hydrogen would be fed into the grid in anything but marginal quantities.

8.5.2 Demand for hydrogen as a fuel

The pipeline systems envisioned in scenarios A + B as regional or local grids and in scenario C as a national system covering a large portion of the industrial parts of the country will mainly serve as energy gas carriers for the generation of heat and steam. A rough estimate of the possible penetration of gas for use as fuel in some chemical process industries is given in Table 8-7. It must be emphasized that the assessment of gas penetration given in the last column is not based on any known data for price elasticity for various fuels and therefore ought to be looked upon as a sheer "guesstimate".

An estimate of the total consumption of energy-rich gases (NG, SNG, GH_2 or a mixture of these) used as a fuel in the chemical process industries under review is collected in Table 8-8 for each of the energy scenarios A, B and C. The table also includes a short summary of quantities consumed as feedstocks. The figures given for NG/GH_2 presume that a national or local gas pipeline system has been constructed.

Table 8-8

Consumption of energy-rich gases in the chemical process industries, PJ.

	1978	1985	2005		2025	
		A, B, C	A, B	C	A, B	C
Feedstock						
GH_2	5	8	6	6	6	6
NG/GH_2	-	0 - 4	0 - 24	0 - 24	0 - 25	0 - 25
Fuel, oil raff.						
internal GH_2	23.5	33	36	36	18	18
NG/GH_2	-	-	0 - 6	0 - 6	0 - 3	0 - 3
Fuel, other chem. industries						
NG/GH_2	-	-	0 - 10	0 - 30	0 - 22	0 - 70
Total	28.5	41 - 45	42 - 82	42 -102	24 - 74	24 -122

Table 8-7

Fuel consumption and penetration of NG/SNG/H_2 in some chemical process industries.

	Consumption of fuel in 1980	Development 1980 - 2025			Fuel consumption 2025	Penetration of purchased NG/SNG/H_2			
						Scenarios A+B		Scenario C	
	1000 toe	Production %/year	Spec energy cons. %/year	Energy use %/year	1000 toe	%	1000 toe	%	1000 toe
Chemical ind.	600*	3.5	-1.5	+2.0	1450	20	300	50	725
Oil refining	800*	-2.0	±0	-2.0	320	0	0	0	0
Rubber and plastic ind.	75	3	-1.0	+2.0	180	20	35	60	110
Silicate ind.	700	1.5	-0.5	1.0	1100	10	110	50	550
Primary metals	75	1.0	-1.0	±0	75	0	-	0	-
Ferro-alloys ind.	5	1.0	-1.0	±0	5	0	-	100	5
Food industry	170	2.0	-1.0	1.0	270	10	25	60	160
TOTAL	2425			+0.75	3400	14	470	46	1550
TOTAL PJ	112				156		21		70

* Including refinery, cracking and other off-gases used for heating purposes.

8.6 Summary

The total fuel used in some chemical process industries may increase by circa 40 % in 50 years and reach a level of 3.4 Mtoe (142 PJ), whereas the consumption of high-energy gases as feedstocks will only increase significantly if the ammonia and methanol industries are developed.

The possible use of NG/SNG/H_2 not internally generated in these industries may reach 0.5 Mtoe (21 PJ) in scenarios A an B and 1.6 Mtoe (70 PJ) in scenario C. On the basis of the price projections assumed in the study for the various energy carriers, it seems unlikely that a major share of these volumes would be covered by pure hydrogen, such as electrolytically generated hydrogen. It seems more probable that the major part of hydrogen use will be in the form of hydrogen enriched gas mixtures based on forest and pulp industry wastes, and peat and kerogen bearing shales for example.

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9. METALLURGICAL INDUSTRY

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9.1 Present production

9.1.1 1974 as a starting point

The structure of the Swedish iron and steel industry has undergone a rapid change during the period 1974 - 1979. Until 1974 the production of steel increased reaching a peak level of 6 Mt in that year. Plans were made for a further increase in production capacity to be achieved in a new plant designated Stålverk 80.

Overcapacity of shipyards on the international scale led to reduced production in the Swedish shipyards. American restrictions of the import of special steel and a general international overcapacity in the steel industry led to a decreased demand for Swedish steel. At first the production was kept at a high level and anything that could not be sold was stored. At this stage the Swedish steel industry was hoping for a new increase in the international demand and preparing for a boom.

By 1976 it became evident that production had to be reduced. The plans for an increased capacity were abandoned. The production fell to a bottom level in 1977, with only 4 Mt of steel produced.

The statistics from this period are very unreliable, since they reflect an extraordinary situation. Changes in demand for various products were met not only by changes in production but also by changes in stocks. The discussion about if and how the capacity should be further decreased affected production, especially in plants where future production was in question.

In consequence, 1974 has been chosen as the base year for this study. This was a year when the Swedish steel industry was utilizing most of its capacity. Although this may mean an overestimate of the steel production, it is probably a better basis for study than the situation during the period 1975 - 1979.

9.1.2 Present production

Sweden produced approximately 6.0 Mt of steel in 1974. The raw materials used were 5.2 Mt of ore and 3.7 Mt of scrap iron. Of the scrap iron, 0.4 Mt was imported, 0.5 Mt was purchased in Sweden, and 2.8 Mt was in the form of internally recycled scrap (1-2).

Table 9-1

Total Swedish production of steel 1970 - 1978.

Year	Production Mtons
1970	5.5
1971	5.2
1972	5.2
1973	5.6
1974	5.9
1975	5.6
1976	5.1
1977	3.9

For a study of the possible uses of H_2 as reductant, the production of sponge-iron is of special interest since some of the methods employed might be modified fairly easily to allow the use of merchant hydrogen. In 1974, the production was approximately 0.2 Mt.

The reduction of iron ore in Sweden is mostly done in blast furnaces. In 1974, Sweden had 15 blast furnaces (1, 3). The largest of these was built in 1973 and has a production capacity of 1 Mt/year. At least 7 of these blast furnaces will be shut down before 1982.

Most of the sponge-iron production is done in 3 plants, of which the biggest was enlarged in 1974 to a production of 110 kt/year.

The iron and steel industry produces not only these commodities but also slag and some other by-products. Some of the Swedish ores have a high content of phosphorus. Slags from such ores are useful as fertilizers. About 0.2 Mt of slag were used for this purpose in 1974 (2).

Blast furnace slag has a composition and structure similar to ordinary portland cement with which it can be mixed without impairing the quality of the product. Cement which contained slag from blast furnaces was produced in Sweden between 1956 and 1974. At present, the Swedish cement industry has an unused production capacity, and the interest in slag-cement is rather low. However, rising prices for fuel might make slag-cement more interesting since the slag may be ground directly into the product, thus saving fuel in the cement kiln.

The blast furnace is also a gas generator. Part of the coke which is used as reducing agent reacts to form a gas consisting of about 20 % CO, 20 % CO_2 and 60 % N_2. This gas is difficult to use since the useful CO fraction is rather small.

A disadvantage of blast furnaces is that they use coke as a reducing agent. The production of coke at present requires special expensive qualities of coal which must be imported. Energy is also lost when the coke is produced (Table 9-2).

Table 9-2

Input and output of energy for a coking plant.

	Input		Output
	MJ/ton coke		MJ/ton coke
Blast furnace gas	1700	Gas	6700
Coal	40200	Coke	28100
Steam	600	Tar	1700
Oil	400	Oil	300
Electricity	70	Loss	6170

At present there is an increasing interest in alternatives to the blast furnace. These should use coal directly, accept coal of low quality and produce a rich gas. Certain processes with all or some of these advantages are now under development and testing.

If the iron and steel industry should make a large-scale change over to H_2-reduction, it is important that the methods used should yield not only iron and steel but also by-products which are the same as or better than those which are obtained at present or are expected in the future. Otherwise, the advantages of H_2-reduction must justify a change not only in the methods of steel production but also in other methods for obtaining the by-products.

The total consumption of fuels and electricity for raw steel production in 1974 was 1.8 Mt of coke, 0.8 Mt of oil and 4.4 TWh of electricity. The import of coke was 1.6 Mt, and 0.5 Mt were produced from imported coal in two Swedish coke ovens.

About 12 Mt of the 36 Mt of iron ore mined in 1974 were presintered. The energy requirement for sintering is 1 GJ of fuel and 0.15 GJ of electricity per ton of ore (5).

It is not possible to distinguish strictly between heating and reduction since the fuel is bonded to oxygen with a bond that is weaker than that between a metal and oxygen. Hence, heat is needed in the reduction process. A rough estimate of the energy balance for the total steel production is given in Table 9.3.

Table 9-3

Annual energy supply and energy use in raw steel production.

	Reduction PJ	Heating PJ	Work etc PJ
Coke	17	34	
Oil		37	
Electricity		11	4.7
Total	17	82	4.7

If the fuels used as reductants were replaced by hydrogen, the energy demand would be 140 kt GH_2, if the condensation energy of the steam produced were not utilized. If instead the energy sources used for heating were replaced by hydrogen, this demand would be 690 kt. The demand for H_2 could thus rise to 830 kt.

The production of raw steel is concentrated to a few large units. A suitably large hydrogen production plant, using e.g. electrolysis, has an annual capacity of 0.14 Mt of H_2. Thus, it would be advantageous to locate the two plant types together so as to obtain short distances for transport. This is of special interest if H_2 is produced by methods that yield pure oxygen as a by-product, e.g. the electrolysis of water, since oxygen is used for the subsequent purificaton of the raw steel, and much more oxygen could be used for combustion processes in the steel industry, as is suggested in 9.3.3.

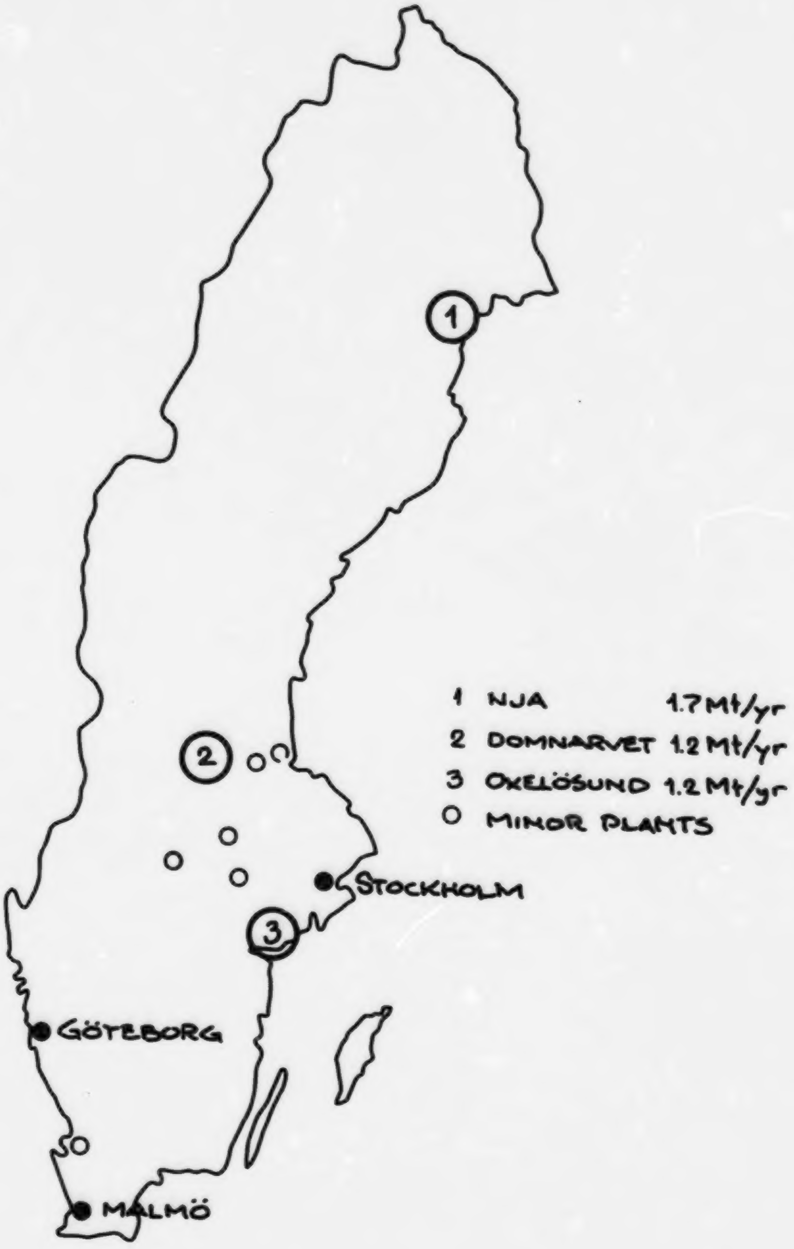
1
2
3
1 NJA 1.7 Mt/yr
2 DOMNARVET 1.2 Mt/yr
3 OXELÖSUND 1.2 Mt/yr
O MINOR PLANTS
STOCKHOLM
GÖTEBORG
MALMÖ

Figure 9-1

Location of the main raw steel plants in Sweden.

Large amounts of energy are required for heating purposes during the purification of raw steel and the manufacture of special steel products. The iron produced in the reduction process might for instance lack the desired composition and therefore require partial remelting or the addition of other metals or other substances. The blooms must be free from surface defects before they are treated further in rolling mills. At present they are cooled down to allow inspection and then reheated to the correct temperature. Furthermore, the production capacity of blooms may not always remain the same as that of rolling mills and other handling stations. Hence it is necessary to store the blooms and keep them heated until they can be treated, Figures 9-2 and 9-3.

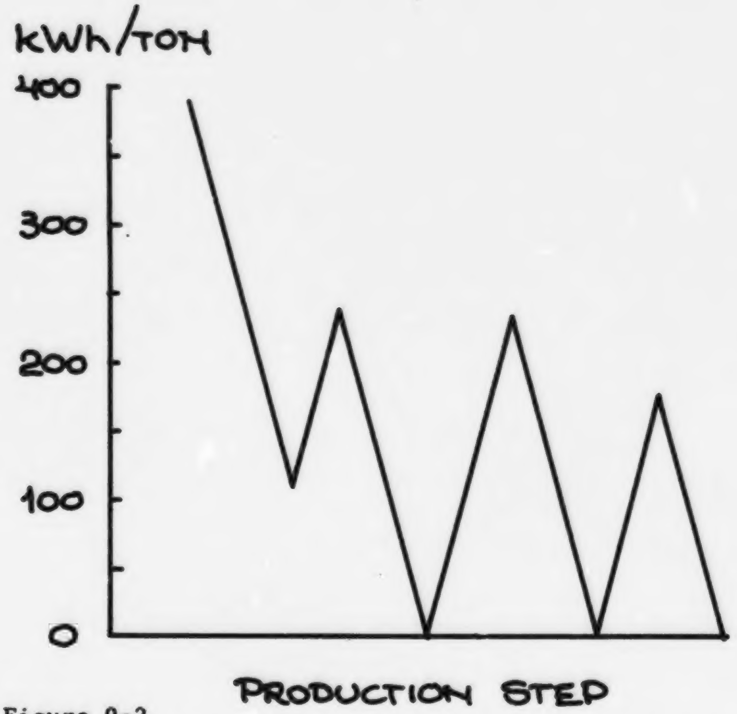

Figure 9-2

Variations in energy content of materials rolled in blooming mills (4).

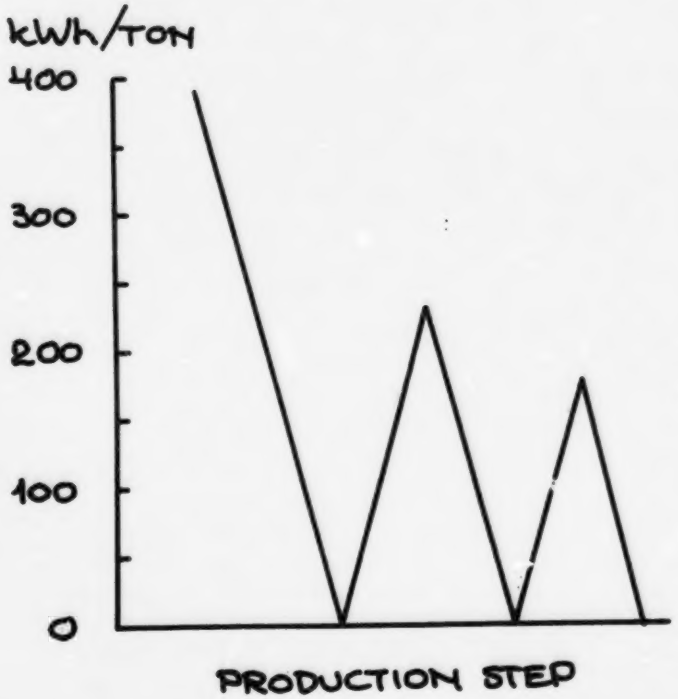

Figure 9-3

Variations in energy content of materials with continuous casting (4).

There are about 250 furnaces in the Swedish steel industry (4). Important goals for current R & D within the field are to find methods for the direct production of various types of steel and alloys in large and small quantities, to inspect and correct defects on hot material, and to make the rolling more flexible. Inspection of hot material is of special interest since many defects probably occur as the material is cooled down. This R & D has been stimulated by the rising costs of fuels and might yield results before 1990 that greatly reduce the need for heating.

9.1.3 Investments in the iron and steel industry

The total investments in the iron and steel industry in May 1975 were insured for 18420 Mcr, 5245 Mcr for plants and 13175 Mcr for machinery etc. During 1974, investments in new plants amounted to 132 Mcr and costs of repairs to existing plants were 90 Mcr. 702 Mcr were spent on machinery etc and 837 Mcr on the repair of equipment in existing plants (1).

The ratio between total value and annual investments can be used as an indication of the average time for the renewal of an industrial section. For the iron and steel industry, this ratio is shown in Table 9-4.

Table 9-4

The ratio between total value and annual investments, i.e.the time needed to renew the capital

	Plants		Equipment		Plants & Equipment	
	Value / New inv.	Value / Inv.+rep.	Value / New inv.	Value / Inv.+rep.	Value / New inv.	Value / Inv.+rep.
1973	39	25	14	8	17	10
1974	40	24	19	9	22	10
1975	16	12	16	8	16	9
1976	13	10	19	9	17	9
1977	37	24	25	11	27	13

In many cases it is difficult to separate new investments from repairs, since equipment is often modified at the same time as it is repaired. The renewal of the production capital is therefore the sum of new investments plus a part of the investments for repairs. The time taken to renew the capital in the iron and steel industry is between 10 and 20 years. For Swedish industry as a whole, the tendency is towards a decrease in the time for capital renewal. It is likely that most of the production capital in the iron and steel industry will be renewed before the year 2000 and renewed at least once again before the year 2025.

Production has been concentrated to a few units. However, these are small compared to the large plants abroad. Consideration has therefore been given as to whether competition on the international market is possible with production units of the size available in Sweden.

The investment costs for blast furnaces and sintering plants of different capacities have been estimated in Table 9-5 (6, 7).

Table 9-5

Investment costs for blast furnaces and sintering plants.

Production capacity Mt/year	Diameter of blast furnace m	Investment per annual ton		
		Blast furnace cr/an.ton	Sintering plant cr/an.ton	Blast furnace + sintering plant cr/an.ton
0.5	6.5	500	120	620
0.8	8	400	80	480
2.5	12	360	65	425
4.0	14.5	325	48	373

For production capacities of less than 1 Mt of iron per year, the coke may advantageously be purchased on the open market. For a unit producing 4.3 Mt of iron/year (Stålverk 80), the investment for coke ovens was estimated to be approximately 200 cr/annual ton of iron (7).

The total investments and the production costs as a function of production capacity are given in Figures 9-4 and 9-5 (7).

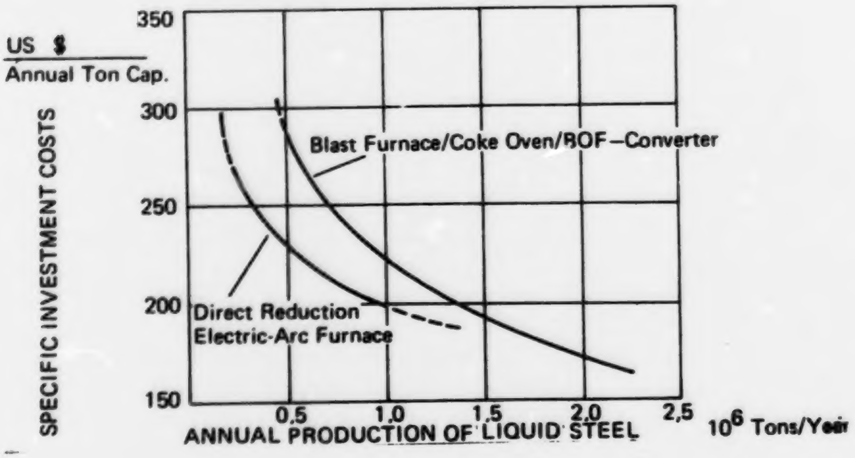

Figure 9-4

Specific investment costs as a function of annual production.

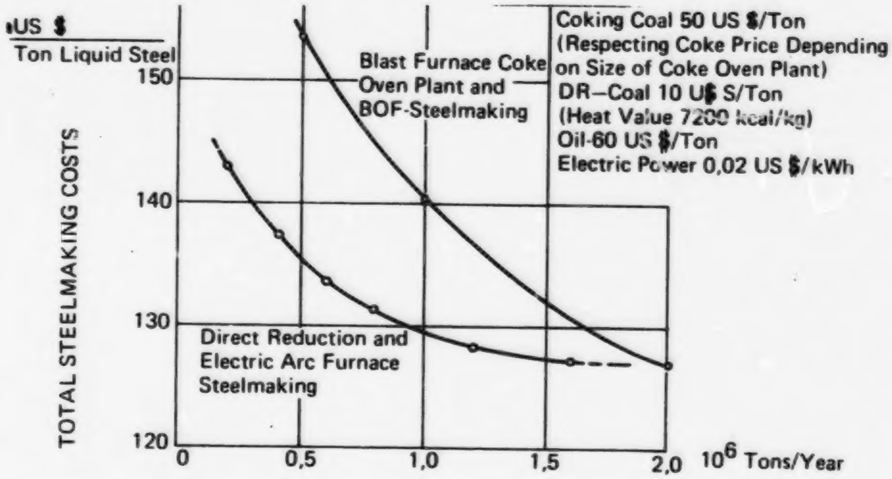

Figure 9-5

Total steelmaking costs as a function of annual production.

At the prices on which these curves are based, a direct reduction to sponge-iron followed by an electric arc furnace steelmaking process becomes competitive with the blast furnace method for a capacity in the region of 1 Mt/year.

9.2 Future production

9.2.1 The future for Swedish steel

Sweden has a long tradition as an iron and steel producing country. Charcoal from wood was used earlier for the reduction of iron ore. Sweden had an excellent combination of rich mines located near large forests during this period. When new processes made reduction with coke possible and more economical than charcoal reduction, the advantage of direct access to a domestic reductant was lost. Access to rich ores was still, however, an advantage until 1970.

In 1900, iron was produced in 161 blast furnaces, all using charcoal. In 1948, the number of blast furnaces had been reduced to 40, of which 30 used charcoal and the rest coke. At that time, the sulphur content in the iron arising from sulphur present in the coke could not be brought down to an acceptable level for the production of high quality steels. The use of charcoal was thus still an advantage in the production of these steels. One decade later the sulphur problem had been solved satisfactorily, and the use of charcoal was no longer an advantage. In 1966, the last blast furnace using charcoal was closed down.

Today the possibility of an increased use of wood as an energy carrier is being discussed. If it turns out that wood and/or other types of biomass, e.g. wood chips, reeds or peat, can compete with the common fuels, it might be of interest to reconsider charcoal as a reductant in the production of iron.

In 1950, Sweden mined about 40 % of the iron ore sold on the world market. Since then many new deposits have been discovered, e.g. in Australia and in Brazil. Sweden still had the advantage, however, of short transportation distances to steel plants in western Europe. As prices for ocean freights have fallen, this advantage has become less significant. The steel industry has also expanded in other parts of the world, as in Japan for example.

The production costs of an ore depend greatly on how it is mined. Underground mining is approximately 50 % more expensive than surface mining. In Sweden, about 85 % of the ore comes from underground mines, while about 70 % of the total world production is surface mined. This means that Swedish ore has comparatively high mining costs (6).

Swedish ores were earlier thought to have a very high quality. However, a considerable part of the ore available in Sweden today has a high phosphorus content, which involves added expense if they are to be rendered suitable for modern processes.

Sweden's competitiveness on the international ore market has thus decreased successively, and Sweden's share of world trade has dropped simultaneously. Today Sweden supplies about 5 % of the iron ore on the world market and produces about 1 % of the global steel consumption (6-7).

The current relationship between the cost of Swedish ore and the international market price is such that imported ore is competitive even in Swedish plants located on the coast, Figure 9-6.

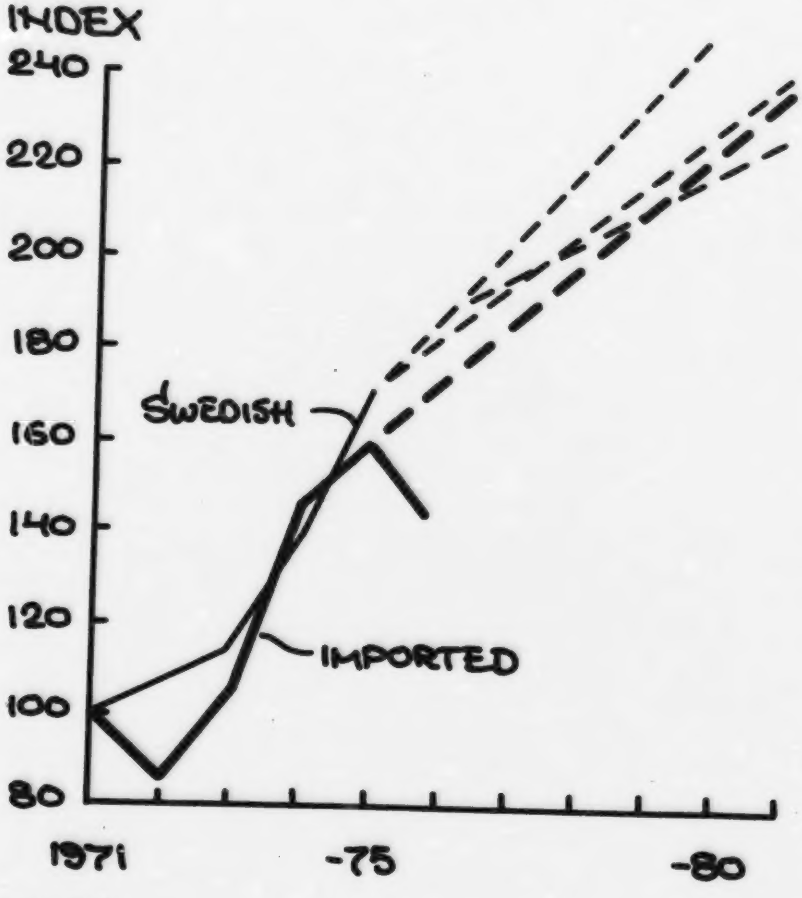

Figure 9-6

Comparison of prices for imported and domestic ore concentrates (6).

A large part of the cost of raw iron depends on the prices of ore, fuel, transportation etc. At today's prices, sponge-iron can be produced in Venezuela and transported to Europe at a cost of about 400 cr/ton, while the production cost for sponge-iron in Europe is about 500 cr/ton. This is mainly due to the low cost of ore and gas in Venezuela, Figure 9-7 (7).

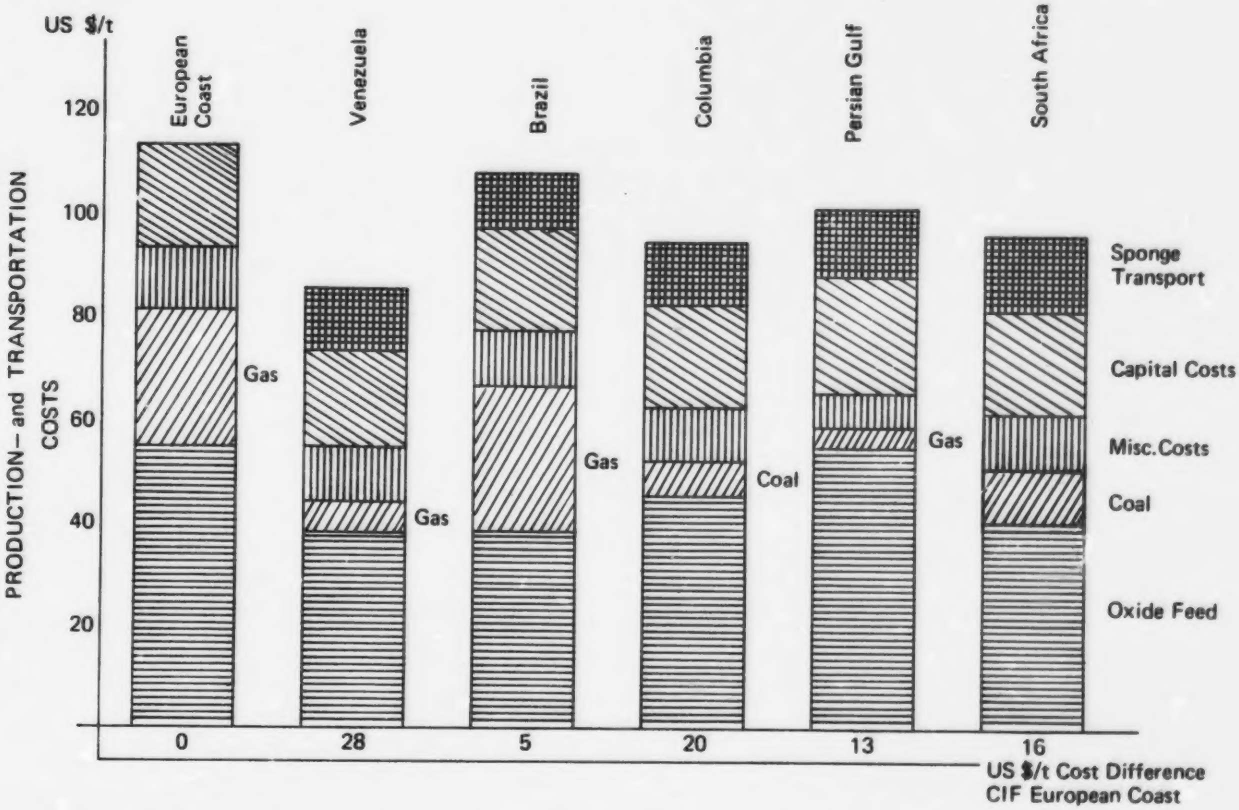

Figure 9-7

Costs for the production and transportation to Europe of sponge-iron in 1976 (7).

Historically, the growth of the Swedish steel industry was based on the following competitive advantages:

- Access to a domestic reducing agent.
- Access to domestic ores.
- Access to knowledge and tradition of steelmaking.

The reductant which is most economically advantageous today is not available in the country. The access to ores of Swedish quality and from Swedish mines does not constitute an important advantage. Thus, the only remaining advantage is knowledge and tradition. It is, however, very doubtful whether this is a sufficient base for a bulk producing industry such as iron and steel manufacture.

One important customer for the Swedish steel industry has been our ship-building industry. In reality, a considerable part of the steel industry has been so closely linked to ship-building that it could be regarded as an integral part. Thus the steel industry has delivered not only thick plates but also prefabricated whole sections for particular ships.

In 1974, the domestic production of steel plates thicker than 4.75 mm was 1.2 Mt. A large part of this production was used by the shipyards. Since 1970, production at the major shipyards has been reduced, and only a few are now building large ships. This of course means a decrease in the market for the steel industry. As long as the ship-building industry could sell its products, the Swedish steel industry had the advantage that it could deliver specially designed products. Hence the steel industry could compete in special products rather than in raw material.

It is very unlikely that ship-building will once again become a big industry in Sweden. Consequently, the steel industry must find alternative users for their services and products. There is no industrial branch in Sweden today that can directly fill the gap left by the shipyards. It seems therefore unlikely that the demand for steel will increase rapidly, at least during the next few decades.

The Swedish steel industry can probably only survive in the long run if it is linked to other branches. One possible solution is that the knowledge stored in the steel industry should be used, not to produce raw or simple steel, but instead to produce high quality goods with a more stable market than ships. A development in this direction could be facilitated by modifications to our economic system that favour the production of highly developed products and inhibit the export of raw materials. Such a development might lead to a demand for processes that can work on a much smaller scale than the processes now used in the steel industry. In this context, new reduction methods, possibly based on hydrogen, might play an important role.

Another possibility is to integrate the reduction of iron ore with the production of electricity, heat and/or certain types of fuels. In a future economy, based on coal instead of oil, iron could be used as a desulphurizing agent in coal gasification. Reduced iron with a high sulphur content (approx. 5 %) would be obtained as a by-product. This iron, together with scrap iron, might constitute the basis of the Swedish steel industry in the future. Since the primary purpose in this case would be coal gasification, the use of hydrogen as a reductant would be of no interest. Water could instead be added to produce a gas containing both H_2 and CO, which can be used for the production of methanol.

If reduction continues to be based on coal, the flows of CO and H_2 from coke ovens, blast furnaces or new reduction processes that yield these waste gases might be used for the production of synthetic fuels. New technology, e.g. plasma synthesis (8), might combine the gasification of oil shales, biomass and carbonaceous wastes with the utilization of waste gases from the steel industry to synthesize alcohols and aliphatic or aromatic hydrocarbons.

9.2.2 The time-lag for the introduction of new methods

The introduction of new technology in the iron and steel industry is in most cases a slow process. Even a change-over to methods that have been used for some time abroad, or that entail minor modifications, can be a slow process. Thus it usually takes about 10 - 15 years for the steel industry to adopt new methods that have been proved feasible.

The time-lag in the introduction of new processes can be demonstrated by the change from older steelmaking processes like the Bessemer, Thomas and Martin processes to more modern methods like the BOF and Kaldo processes.

During a period of about 10 years, between 1965 and 1974, the use of older steelmaking processes dropped from 40 % to 20 %. The total production increased simultaneously from 4.7 Mt to 6.0 Mt. The production in older plants was almost unchanged, although the percentage of steel produced by their methods decreased owing to the increased production in new plants.

Table 9-6

Steelmaking processes in Sweden and the OECD (6).

Process	1965						1974					
	Sweden		OECD Europe		OECD Total		Sweden		OECD Europe		OECD Total	
	Mt	%	Mt	%	Mt	%	Mt	%	Mt	%	Mt	%
Thomas	0.4	8	33	26	33	11	-	-	11	6	11	3
Martin	1.5	32	49	39	150	51	1.2	19	27	15	66	15
Electric	1.8	38	18	14	40	14	2.5	42	34	18	84	18
Oxygen (BOF, OBM, Kaldo etc)	1.0	22	26	21	73	24	2.3	38	111	61	293	64
Total	4.7		126		296		6.0		183		454	
Cast iron	0.04	1	1.4	1			1.1	18	20	11		

In 1965, continuous casting accounted for about 1 % of the total steel production. In 1974, the use of continuous casting had increased considerably, to about 18 %. The figures reflect the fact that investments in the steel industry are large. When a new method is introduced, the old plants can often compete since their investment costs have been paid off. There is accordingly a tendency to keep even older plants running, particularly when the demand is high compared with the total production capacity.

The use of hydrogen as a reductant is thus not likely to play any significant role in the Swedish iron and steel industry during the next decades, unless a hydrogen-based process can be shown to have advantages over alternative methods. Such advantages might be:

- the lowering of production costs, including environmental considerations,
- better economy even for small plants, giving increased flexibility,
- better products or new types of products.

One important reason for the large investments, and thus for the slow change of methods, is that ordinary reduction processes are slow. In order to achieve acceptable production rates, it is necessary to have a large quantity of ore in the furnace, so that the furnace must also be large. With a fast reduction process, e.g. a hydrogen-based plasma process, it might be possible to achieve acceptable production with a very small reactor containing only about 1 kg of ore. Such a process would have the advantage of increased flexibility and would also facilitate a more rapid change than has taken place in the past.

9.3 Theoretical consideration

9.3.1 Reduction

In a mineral oxide, oxygen is removed and restored at the surface of the particles. In ordinary air, the flow of oxygen from a particle balances the flow of oxygen into it, and the composition is stable. One way of removing oxygen from the surrounding gas is to use a reducing agent, i.e. a substance that will react with oxygen and form stable molecules that will not react with the lattice.

The most common reducers for oxidic ores are C, CO and H_2. They remove oxygen by forming CO or CO_2, CO_2 and H_2O, If these products do not react with the metal the ore is reduced. In some special cases other reducing agents, e.g. Al, are used. Free electrons can also be used for reduction, e.g. in electrolysis.

If a metal oxide is placed in pure hydrogen and heated, oxygen will flow from the oxide and form water with the surrounding H_2. At high temperatures, the water formed is partly decomposed. Oxygen will thus start to flow back and balance the outflow. A complete reduction is only obtained if the partial pressure of H_2O in the surrounding gas is kept very low.

Further, for a rapid process it is essential to have a high temperature, a large surface where ore and reductant can interact and a low oxygen pressure in the reductant. Hence a direct reduction to unmolten metal is inherently a slow process because of the low temperature. Processes in a molten bath, e.g. injection smelting reduction, could be faster. In the extreme "temperature" of a plasma, the reaction proceeds very rapidly.

9.3.2 The reduction of iron ore

Most common iron ores consist mainly of Fe_2O_3. Ores consisting of Fe_3O_4 or FeS_2 are also frequent. In Swedish ores, Fe_3O_4 is more abundant than Fe_2O_3. The advantage of a lower oxidation state is, however, lost in the sintering process where most of the ore is oxidized to Fe_2O_3. Domestic FeS_2 ores are mainly used for the production of sulphuric acid. Fe_3O_4 from this process is available.

The reduction of Fe_2O_3 (hematite) to Fe_3O_4 (magnetite) and of Fe_3O_4 to FeO (wustite) is possible at a partial water pressure that is higher than that for the reduction of FeO to Fe. Thus, if all the steps are carried out in the same gas, the last step therefore determines the acceptable water pressure. Usually the steps are separated so that fresh reduction gas with a low content of H_2O is used for the reduction of FeO to Fe. The mixture of H_2 and H_2O formed is introduced into the prereduction step where Fe_2O_3 is reduced to FeO, Figure 9-8.

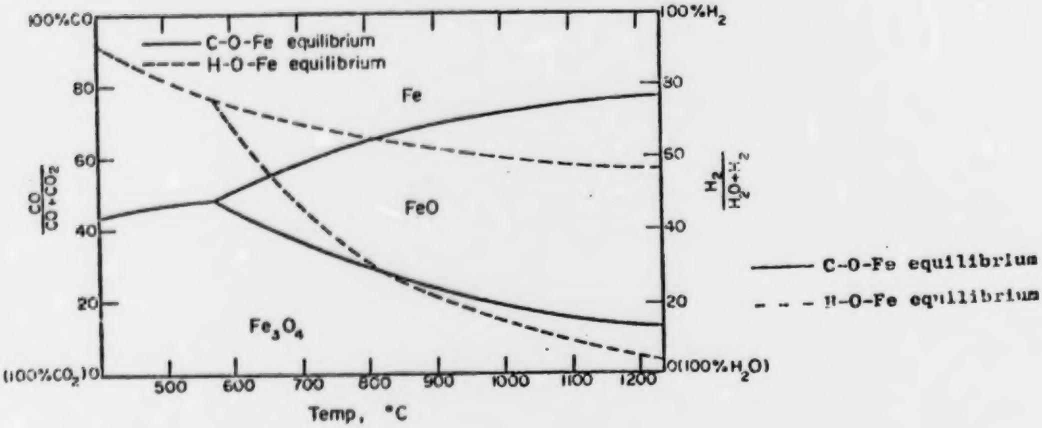

Figure 9-8

Equilibrium reduction curves for iron ores (9).

From these curves it can be seen that H_2 is a "better" reducing agent than CO at high temperature (> 1090 K). It also differs from CO in another respect since CO is not only a reducing agent but also a carburizing agent. When CO is used as a reductant it is therefore possible to make a product with the desired grade of carbon. The degree of carburization can be controlled by the composition of the gas and the temperature. If H_2 is used as the reducing agent and a carburized product is desired, carbon must be added by some other means.

The reduction of Fe_2O_3 requires at least 54 kg of H_2 and 0.86 GJ of additional heat per ton of formed metal.

9.3.3 Oxygen

9.3.3.1 Oxygen in combustion processes

If hydrogen is produced by electrolysis, pure oxygen is obtained as a by-product. Consequently, the demand for oxygen is an important aspect in a hydrogen economy.

In 1974, the total Swedish production of oxygen was 0.5 Mt, which was sold at an average price of 170 cr/ton. Most of it was used within the country. The steel industry used about 13 kt of liquid oxygen and $260 \cdot 10^6$ m^3 of gaseous oxygen, i.e. about 390 kt in all. About half the quantity was used for steel refining, Figure 9-9 and Table 9-7.

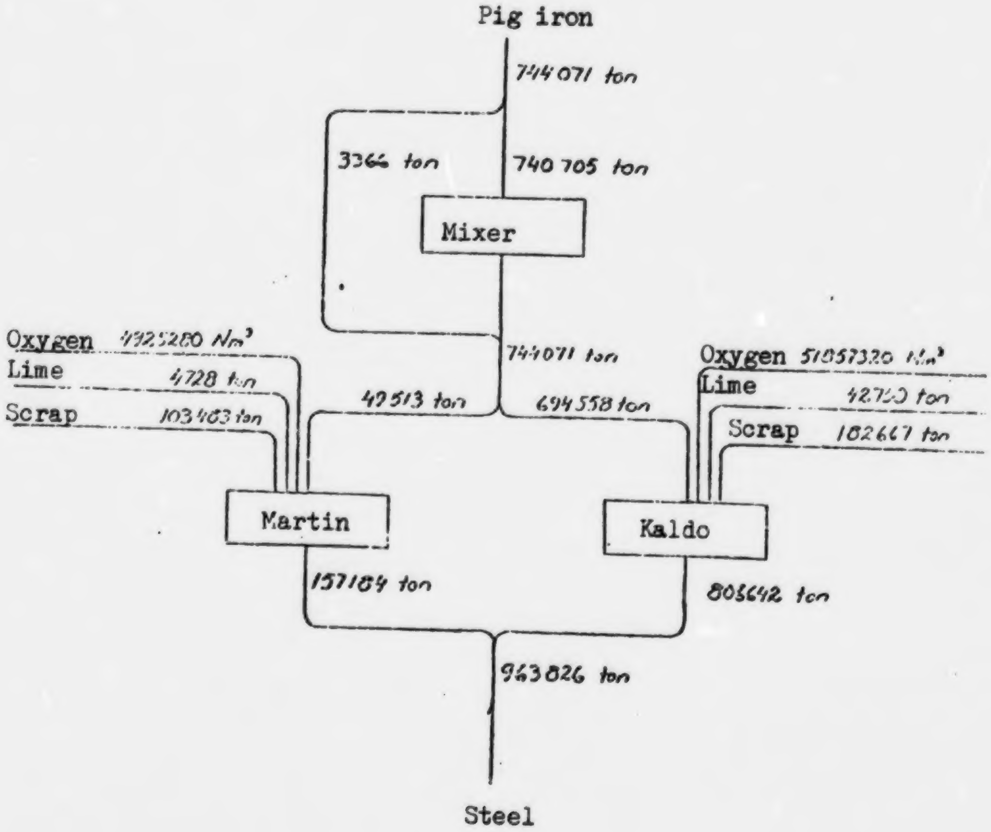
Pig iron
744 071 ton
3366 ton
740 705 ton
Mixer
744 071 ton
Oxygen 4925280 Nm³
Lime 4728 ton
Scrap 103 483 ton
49 513 ton
694 558 ton
Oxygen 51857320 Nm³
Lime 42750 ton
Scrap 182 667 ton
Martin
Kaldo
157184 ton
806642 ton
963 826 ton
Steel

Figure 9-9

Annual flow of materials in a steel plant (Oxelösund) (4).

Table 9-7

Raw materials for steel production (4).

Process	Pig iron kg/ton steel	Oxygen Nm^3/ton steel	Burnt lime kg/ton steel	Scrap kg/ton steel
Martin	443	31	30	658
Kaldo	882	64	53	227
BOF	889	49	67	161

Oxygen is also of interest for all combustion processes, especially processes where high temperatures are necessary. For a process where the fuel is coke and the exhaust gases leave at 1400 F, the efficiency can be almost doubled if oxygen is used instead of air. If the oxygen price is less than 175 cr/ton this might be an economic way to save coke.

9.3.3.2 Oxygen and hydrogen

The use of oxygen instead of air for high temperature processes is not quite as favourable with hydrogen as with coke. The efficiency of a process where the exhaust gases leave at a high temperature will, of course, increase if air is replaced by oxygen, but it will still be low compared with electric heating.

For low temperature processes, it might in some cases be of interest to burn pure hydrogen and pure oxygen and to cool the exhaust gases under 373 K in order to condense the water. Such an exhaust-free combustion might be of interest in special cases, e.g. as a way to get a very high peak power without overloading the electricity supply.

9.4 Some reduction processes using H_2

9.4.1 Processes used today

The number of possible processes is large. In a study from 1976 (10), 54 processes for the production of sponge-iron are described, some of these using H_2. Only a few of the most important methods will be discussed here.

9.4.1.1 The Hojalata y Lamina (HyL) process

In this Mexican process, Figure 9-10, methane is cracked with water to give a gas containing 73 % H_2, 16 % CH_4 and 7 % CO_2. This gas is used for the reduction of iron ore that has been prereduced to FeO. Hot gas (> 1400 K) is fed into a container with hot (> 1200 K) FeO, and the FeO is reduced to Fe. Water is removed from the gas leaving the container, and the gas is then fed to another container of the same type where it heats and prereduces iron ore.

When the reduction of FeO is completed after about 2 hours, the iron is taken out and the container is refilled with ore. The process is continued but with the two containers in exchanged positions (9).

The gas consumption is about 500 m^3 per ton of iron, i.e. about 15 GJ. This is about the same amount of energy as that used in a blast furnace with a coke oven (14 - 18 GJ). About 15 % of the energy content of the natural gas fed into the reformer is, however, lost in the reforming process. It seems reasonable to expect that H_2 could be used to some extent instead of the reformer gas, thereby reducing the energy losses.

The process is primarily adapted and suited to the availability of large volumes of low-cost natural gas. With H_2 as the reducing gas, it has no inherent advantages over the Wiberg process unless H_2 becomes cheaper than coal.

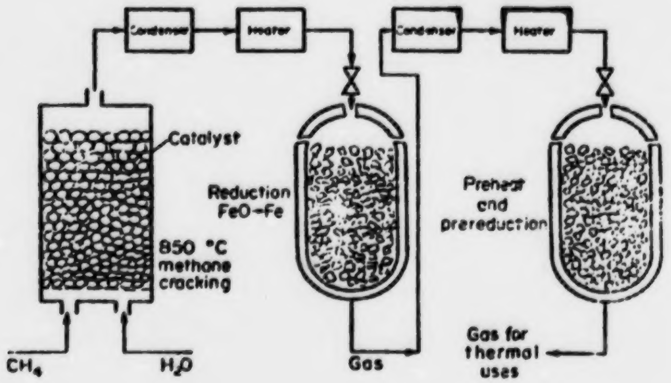

Figure 9-10

Simplified diagram of the HyL process (9).

9.4.1.2 The Midrex process

The Midrex process uses a mixture of CO and H_2 as the reducing gas, Figure 9-11. This gas is produced from natural gas in a catalytic reformer and fed to a shaft furnace, where it passes through a bed of iron ore. The ore is reduced and the gas is oxidized to CO_2 and H_2O. The exhaust gas, consisting of CO_2, H_2O and some CO and H_2, is fed back to the reformer.

About 12.6 GJ of gas is used to produce 1 ton of reduced iron. This is slightly better than for a blast furnace with a coke oven (about 20 % less energy) (7, 9, 11). However, the difference is not large enough to make the process interesting for Sweden, at least not until natural gas or H_2 is introduced and available for some other reasons.

The Purofer and Armco processes are similar to the Midrex process. The difference between these processes is mainly that the conversion of natural gas to a mixture of CO and H_2 is done in slightly different ways.

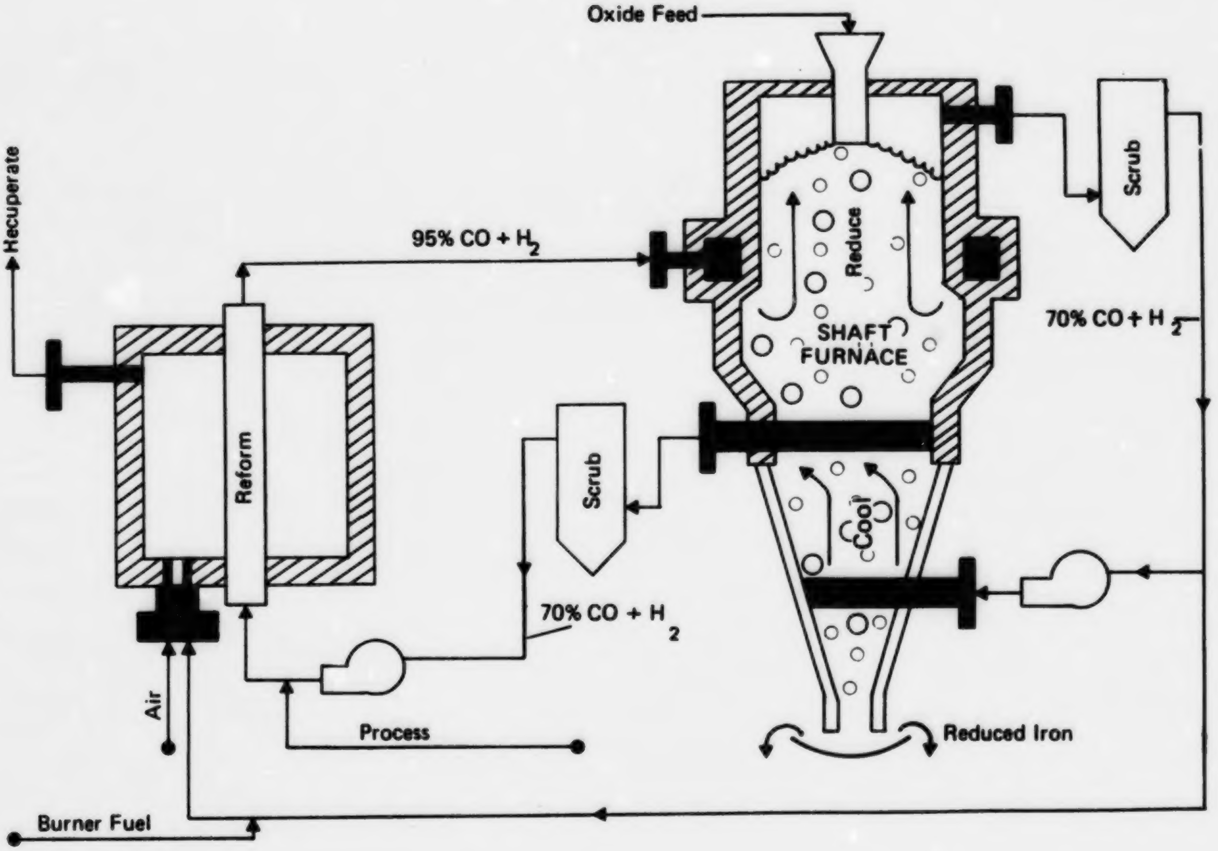

Figure 9-11

The Midrex process (7).

9.4.1.3 The Wiberg process

The Wiberg process has been developed in Sweden. It has the highest efficiency of the methods used today, but the total energy economy is disputable since part of the energy is supplied in the form of electricity. Earlier, Sweden had access to unused hydropower which could be used for the production of electricity. Reduction methods which used electricity were then not disadvantageous. Today the demand for electricity exceeds what can be produced with hydroelectric power. Hence, an increase in the use of electricity must be met by an increased production from fossil fuels and/or nuclear power. The total efficiency of a process should therefore also include the efficiency of electricity production from available fuels.

The Wiberg process, Figure 9-12, is a continuous process yielding sponge iron. Iron ore and a reducing gas circulate in mutually opposite directions in a reactor. The gas, containing 67 % CO, 28 % H_2, 3 % CO_2 and 2 % H_2O, is fed to the bottom of the reactor. As it passes upwards it reduces FeO to Fe. When it reaches a level where it is in equilibrium with FeO, 75 % of the gas is taken out. At this level the gas contains 48 % CO, 22 % CO_2, 21 % H_2 and

9 % H_2O. The part of the gas that is taken out is recycled to a gas generator. The remainder passes up the shaft and prereduces the ore to wustite. In this upper section, air is admitted to burn the residual gas and preheat the charge.

The recycled gas is mixed with steam and then drawn through a bed of heated coke. Here H_2O is reduced to H_2 and CO_2 to CO, and the composition of the reducing gas is restored. One problem is that the coke contains some sulphur that must be removed from the reducing gas. Therefore, at the exit of the regenerator, the gas is passed through a bed of calcinated dolomite where the sulphur is removed (7, 9).

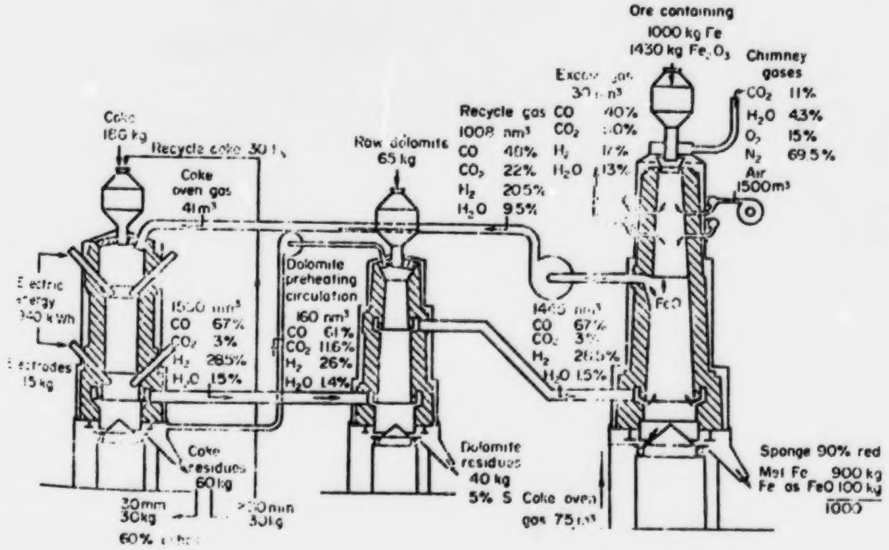
Ore containing
1000 kg Fe
1430 kg Fe2O3
Chimney gases
CO2 11%
H2O 43%
O2 15%
N2 69.5%
Air 1500m³
Excess gas
Recycle gas
1008 nm³
CO 40%
CO2 22%
H2 20.5%
H2O 9.5%
CO 40%
H2O 13%
Coke 186 kg
Recycle coke 30 kg
Coke oven gas 41 m³
Raw dolomite 65 kg
Electric energy
Electrodes 15 kg
CO 67%
CO2 3%
H2 28.5%
H2O 1.5%
Dolomite preheating circulation
160 nm³
CO 61%
CO2 11.6%
H2 26%
H2O 1.4%
CO 67%
CO2 3%
H2O 1.5%
FeO
Coke residues 60 kg
30 mm 30kg
60% coke
30 kg
Dolomite residues 40 kg 5% S
Coke oven gas
Sponge 90% red
Met Fe 900 kg
Fe as FeO 100 kg
1000

Figure 9-12

The Wiberg process (9).

In this way 1 ton of iron can be produced with e.g. 120 kg of coke = 3.4 GJ, 50 kg of C_3H_8 = 2.8 GJ and 800 kWh of electricity = 2.9 GJ, i.e. with 9.1 GJ (3).

A modified Wiberg process has been proposed by SKF steel, where the regenerator is replaced by a plasma reactor. In this way it is possible to increase the efficiency in the regeneration of the reducing gas. Preliminary estimations show that it will be possible to produce 1 ton of iron with 160 kg of hydrocarbons and 735 kWh of electricity, i.e. approximately 9 GJ. In this modified process, it is also possible to make some further improvements which will reduce the energy consumption to 8.4 GJ/ton Fe.

If H_2 should become available at a low price it might be interesting to consider a process similar to the Wiberg process but with some other type of regeneration of the reducing gas. Instead of coke and steam, it might be possible to use a mixture of CO_2 and H_2 for the regeneration.

The Wiberg process has, however, some serious disadvantages, and it is unlikely that this process could contribute significantly to steel production. Although very pure sponge-iron is produced from pure ore, more impure ores are difficult to handle. The process is also slow. Existing plants (2 in Sweden and 1 in Japan) have rather low capacities of less than 0.2 Mt/year.

9.4.1.4 Fluidized beds

In a fluidized bed, a gas flow is drawn through a bed of finely divided solids and keeps the solid particles in circulation. The system acts like a suspension of solid particles in gas. Since all the solid particles "float" in the gas, the surface where gas and solid can interact is almost the total surface of the particles.

One process using fluidized beds is the FIOR process, Figure 9-13. This process is designed for porous ores with grain sizes less than 9 mm. It operates at 1000 K and a pressure of 1.2 - 1.5 MPa. The energy requirements are about 16 GJ/ton of iron (11).

The FIOR process or a similar process could be of interest if cheap natural gas or cheap H_2 becomes available together with an ore of suitable quality. Today it seems unlikely that such a process will be of interest in Sweden.

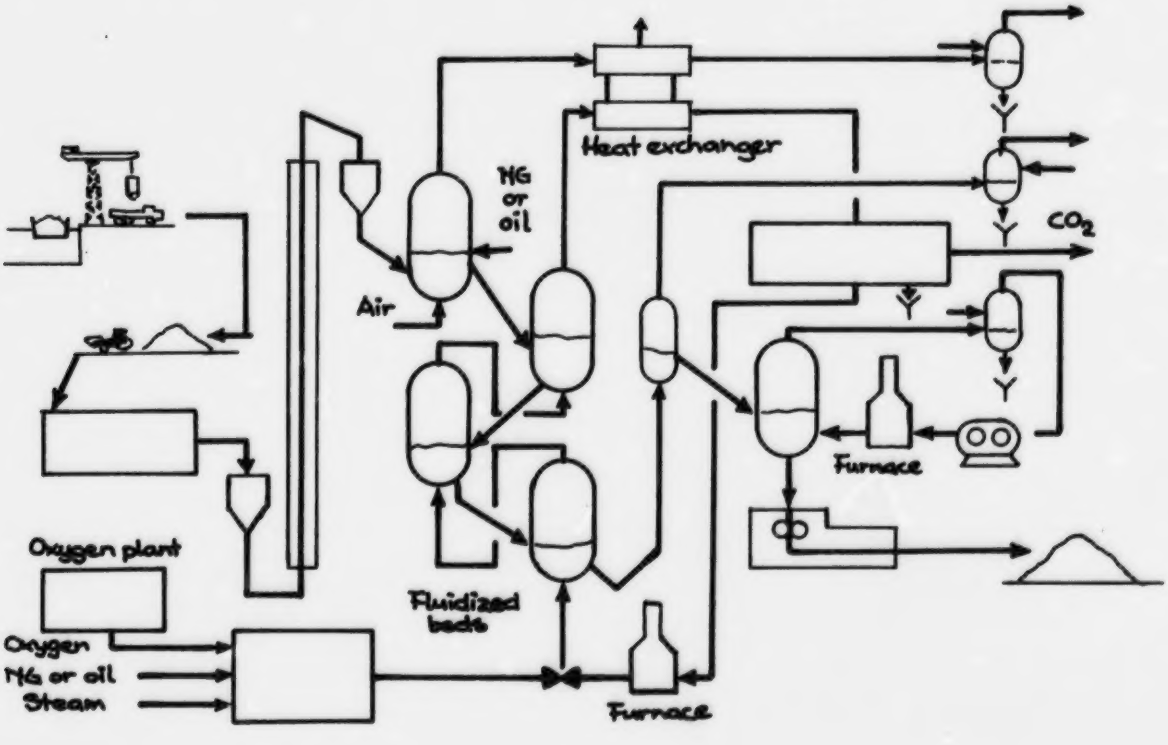

Figure 9-13

The FIOR process (11).

9.4.2 New processes

9.4.2.1 Conred

Conred 1 is a method suggested by Stora Kopparbergs Bergslags AB (Swedish patent appl 76-03359-6). Oxygen, hydrogen and other fuels are injected together with prereduced ore concentrate into a bath of molten iron. The exhaust gases from the bath are used for the prereduction of ore concentrate in fluidized beds. Heat from the exhaust gases is used for the production of electricity.

If an excess of fuel, e.g. heavy oil, is supplied, then more hydrogen can be produced than is consumed. A Conred process may thus be used for the production of hydrogen. If the oxygen is obtained from air, N_2 becomes a by-product. It may therefore be of interest to combine Conred with the manufacture of ammonia from the by-products.

In an economy with an increasing demand for hydrogen, it is also of interest to consider Conred as a method for producing H_2, especially if the electricity produced is used for oxygen production via electrolysis instead of taking the oxygen from air.

Should hydrogen become available in large amounts at a low price, then a modified Conred concept could become of interest. Merchant hydrogen could be used directly for the reduction stages in Conred. However, a number of problems associated with such a process have not yet been solved (7).

Stora Kopparberg is at present engaged in developing another method for smelting reduction, called Elred. Further work on Conred is not planned unless Elred fails.

9.4.2.2 Injection smelting reduction

The smelting reduction process proposed in "The Future Steelplant" (13) does not use H_2. However, it is of interest in this context since it produces a rich exhaust gas which might be used for H_2 production or be fed to a transmission network for NG and/or H_2. It is also of interest since the gas contains CO, which could be used together with H_2 for the production of methanol. In an economy with a high demand for rich gases, the process might also be used as a gasification process with iron as a by-product, at a price that makes other reduction processes obsolete.

The process is basically a smelting reduction process where ore concentrate, coal powder and oxygen are injected into a hot metal bath with the simultaneous reduction of iron oxide and combustion of part of the coal to carbon monoxide. The reducing agent is carbon, and heat is supplied to the process by the combustion of coal and/or by means of induction heating. The required process heat may be supplied either by externally produced electricity or by electricity produced from coal powder, with recycling of the waste gas energy as electricity by way of a turbine.

The oxygen potential of the bath is maintained at a very low level. The carbon is only oxidized to carbon monoxide, and the hydrogen in the coal is not oxidized at all. The exhaust gases are rich since they contain no nitrogen. The chemical heat content is 12.5 MJ/Nm^3, and the temperature of the gas is approximately 1450°C. If the energy of the gas is converted into electrical energy, all the process energy can be supplied by the coal, including the energy for oxygen production. However, such a solution is not practical, especially in a situation where the demands for gaseous fuel for other purposes are high.

The hot metal product contains approximately 4 % of carbon, a great deal of sulphur, and certain amounts of phosphorus, silicon and manganese.

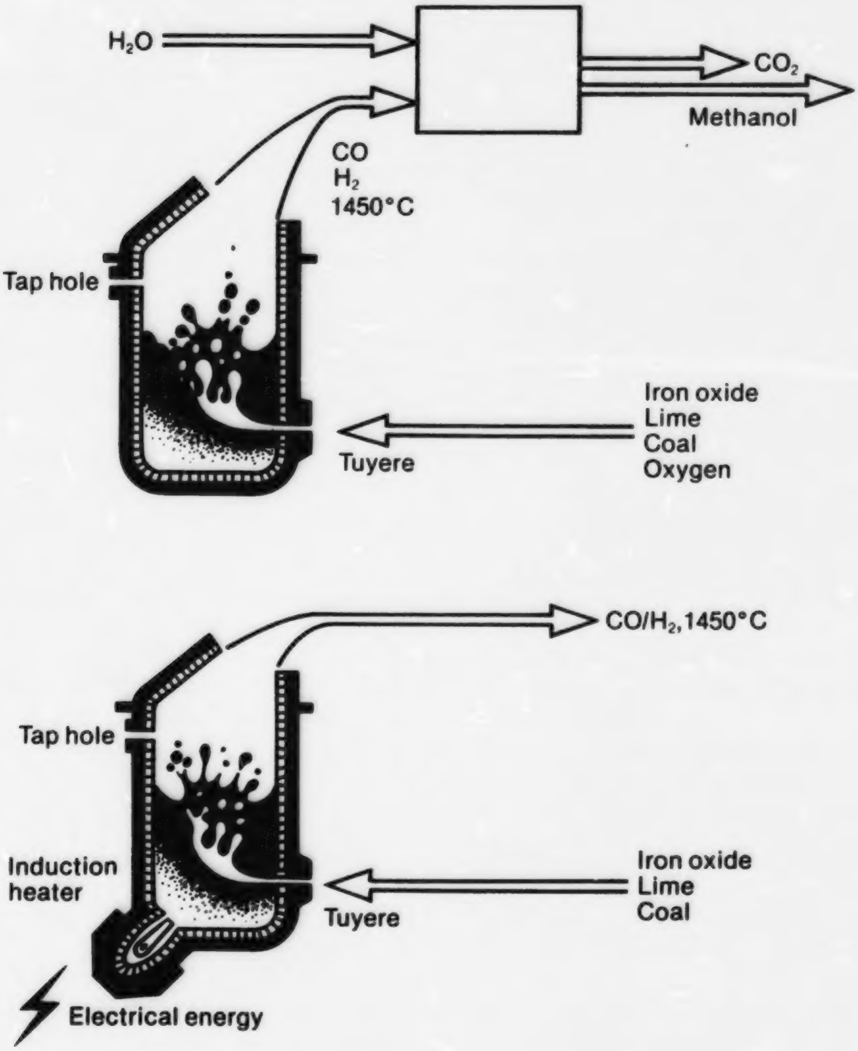
H_2O
CO_2
Methanol
CO
H_2
1450°C
Tap hole
Iron oxide
Lime
Coal
Oxygen
Tuyere
CO/H_2, 1450°C
Tap hole
Induction heater
Iron oxide
Lime
Coal
Tuyere
Electrical energy

Figure 9-14

Sketches showing the two extreme forms of the injection process in principle. In the top version, the process is powered by coal, while provision is made for electric heating in the bottom version (13).

9.4.2.3 Plasma reduction

In order to reduce a metal oxide, phonons that can break the bond between metal and oxygen must be supplied. The speed of the process thus depends on the number of sufficiently energetic phonons that are present per second. The higher the temperature, the larger is the number of sufficiently energetic phonons available.

At very high gas temperatures, the phonons will be energetic enough to break the bonds between electrons and nuclei in the gas. The gas will then turn into an electrically conducting plasma. Since the plasma is an electric conductor, energy can easily be supplied to keep the "temperature" of the plasma high simply by means of an electric current through the plasma.

Most of the phonons in a plasma have sufficient energy to break a metal-oxygen bond. If the oxygen is removed, then the oxide will rapidly be reduced by the large number of sufficiently energetic phonons available in the plasma.

The reduction in a plasma may be so fast that an oxide powder can be reduced while it is falling through the plasma. The reduction time is of the order of milliseconds rather than hours, as in present methods. A small charge in a plasma reactor gives therefore similar capacities as large ones in conventional processes. In e.g. the HyL process, a complete cycle takes 5 hours. Thus the charge must contain 5 tons of Fe, if 1 ton/hour is desired. In a plasma reactor operating with a cycle of 1 second, a charge of 0.3 kg Fe will give 1 ton/hour.

Since the charge in a plasma reactor is small, the reactor can be small. A plasma is normally "heated" directly by passing an electric current through it, rather than indirectly through hot reactor walls. Therefore a plasma reactor seems to be the ideal tool for intermittent production. When it is turned on, it will start to work almost instantly, and when it is turned off the heat stored in walls etc is small because of the small size of the reactor.

In an economy where the production of steel is no longer considered as a separate industrial branch but as an integrated part of the production of machinery etc, the plasma reactor may be very interesting. Even small workshops may buy scrap and ore as raw material instead of steel. By using a plasma reactor, turned on in the morning and turned off at the end of the day, they can produce their steel in shapes that are appropriate for the final product. Hence the work of rolling, milling, cutting, turning etc can be reduced, and the quality of the material can be adapted directly to the final product.

The oxygen that is removed from the oxide must be taken from the reactor to prevent reoxidization of the metal. This could be done by circulating hydrogen through the reactor, Figure 9-15.

One problem with plasma reactors has been to generate a sufficiently large and stable plasma. An interesting solution to this problem is the English method called Expanded Precessive Plasma, EPP (8), and its further development called Sustained Shockwave Plasma, SSP (5). In both methods a plasma is produced, between either an orbiting electrode and a ring-shaped anode

(EPP), or a number of stationary cathodes and a sectioned anode ringe (SSP). A plasma volume of truncated cone shape is produced. The large plasma volume is stable even with very tense particle entrainment, especially in the SSP process.

Preliminary tests with the SSP plasma method are planned to commence in Sweden in 1980 in cooperation with the University of Minnesota.

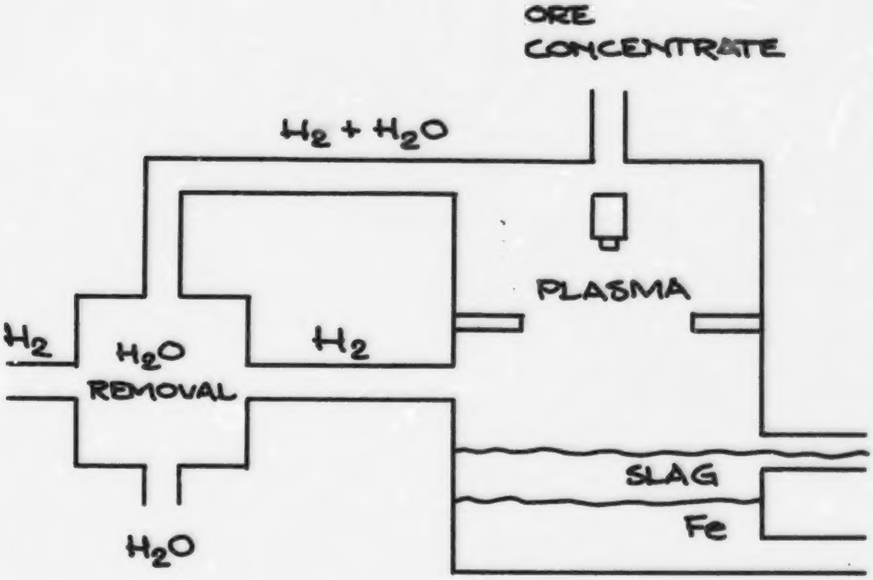

Figure 9-15

Simplified diagram of a hydrogen based plasma process.

9.4.3 Raw steel costs for different production methods

The raw steel production costs given in Tables 9-9 - 9-12 are based on the prices in Table 9-8. All estimations of costs are based on the monetary value of 1978. This means that all prices are assumed to be the same in 2025 as in 1978, with the exception of the prices for fuels and electricity. For further discussions about prices of fuels, see Chapter 5.

Table 9-8

Costs of fuels and raw materials in 1978 and 2025

	Unit	1978	2025
Coal	cr/GJ	6.20	14.6
Coke	cr/GJ	13.6	32.2
Crude oil	cr/GJ	11.0	33.5
NG or SNG	cr/GJ	10.5	34
Hydrogen	cr/GJ	(54)	62
Electricity	cr/GJ	24.4	54
Oxygen (impure)	cr/Nm^3	0.07	0.15
Oxygen (pure)	cr/Nm^3	0.27	0.58
Ore concentrate	cr/ton	70	70
Lime	cr/ton	180	180
Labour	cr/hour	100	100

The investment costs for 1978 have been estimated using actual costs for existing plants and rough calculations for new methods (injection smelting reduction and plasma reduction), based on estimates of the size and complexity for these plants. The investment costs for 2025 have been assumed to be the same as the investment costs for 1978.

The annual cost of investments is based on a pay-off time of 20 years and 4 % real interest, which means an annual cost of 7.37 % of the total investment cost.

All investment costs are based on an annual production time of 8000 hours. For the plasma process, it is possible to turn the equipment on and off so that it can be used for daytime production only. If this possibility is utilized, then the production time for a plasma reactor will be only 1600 hours/year. The investment costs for a production of 1 ton of steel in a plasma reactor will then, of course, be higher than for a continuously operating reactor. However, the posssibility of operating plasma reactors during the daytime will only be utilized if the advantage of daytime operation is valued higher than low investments.

Tables 9-9 - 9-12 and Figure 9-16 show that the different methods can be grouped into three groups with production costs around -300, 1000 or 1500 cr/ton of steel.

-300 cr/ton steel in 2025

This negative production cost is possible for either a large-scale or a small-scale injection smelting reduction process, provided that the gas produced can be sold at the same price as synthetic natural gas, i.e. 34 cr/GJ in 2025. The gas produced is a rich gas with about 12 MJ/Nm^3, i.e. the heat obtained is about 1/3 of that from SNG. At present it is planned to investigate the possibility of using the gas for methanol production. If no other demand for the gas can be found, it could be used for the prereduction of ore. The costs will then rise to between -300 cr/ton of steel and 1500 cr/ton of steel depending on how much of the gas can be used.

1000 cr/ton steel in 2025

1000 cr/ton of steel could be reached in either small-scale or large-scale production with a hydrogen based plasma process. A very important advantage with the plasma process is that it can be run in the daytime only, but then of course at a somewhat higher cost (approx 1200 cr/ton of steel).

The same production cost can also be obtained in large-scale production with a blast furnace, and in small and large scale production with the Wiberg process.

1500 cr/ton steel in 2025

1500 cr/ton of steel will be the cost for the blast furnace process adapted for small-scale production. It is also the cost for the injection smelting reduction process on a small or a large scale if the gas produced is not utilized at all.

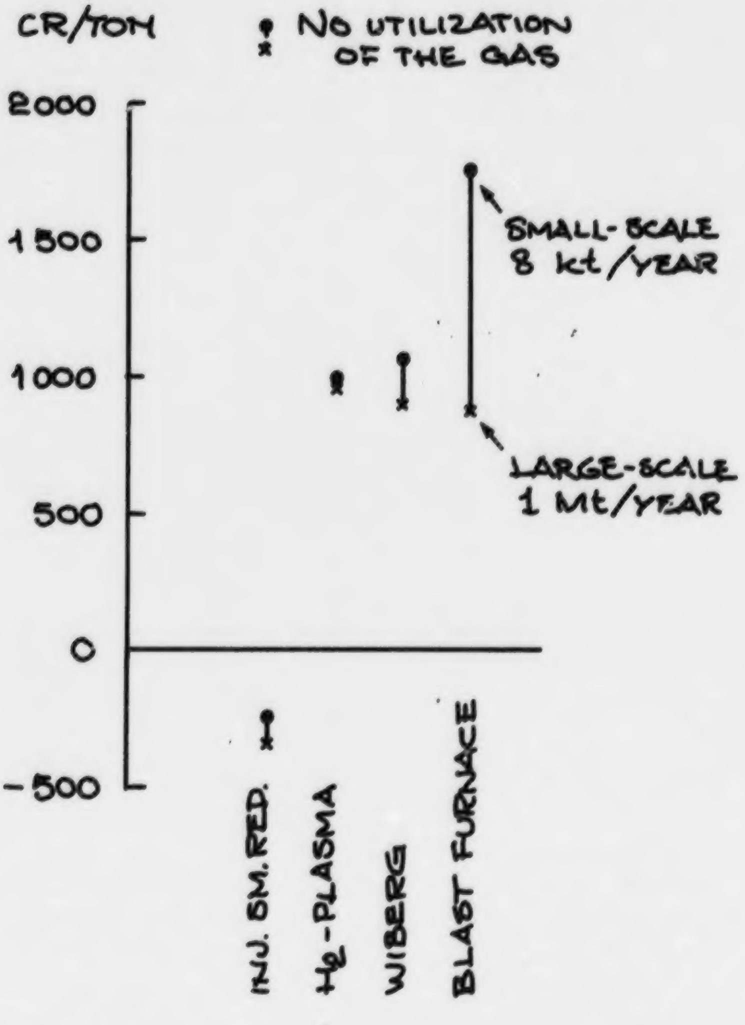

Figure 9-16

Production costs for various ore reduction methods in 2025.

Table 9-9

Energy costs per ton of steel, 1978.

	Blast furnace with sintering of ore		Wiberg process with sintering of ore		Injection smelting reduction of magnetite		Plasma with H_2 reduction of magnetite	
	GJ	cr	GJ	cr	GJ	cr	GJ	cr
Ore reduction								
Coke	15.8	215	3.9	53				
Coal					99	614		
Oil	1.3	12						
Gas			2.6	27	-75	-788		
H_2							5.6	262
Electrical energy	0.5	12	3.3	81			6.3	154
Oxygen (impure)					(2200 Nm^3)	154		
Sub total		239		161		-20		416
Refining								
Oxygen (pure)	(58 Nm^3)	16				6		
Coal							0.4	2
Electricity			5.4	132	1.0	25	1.1	27
Total		257		293		11		445

Table 9-10

Total steel making costs 1978 for small-scale and large-scale production (cr per ton of metal).

a. Small-scale production in a microplant as part of a production line in a workshop
(1 ton/hour = 8 kt/year)

	Blast furnace process	Wiberg process	Injection smelting reduction	Plasma with hydrogen
Ore concentrate	130	130	130	130
Fuels, electr. and oxygen	257	293	11	445
Lime	30	6	100	1
Investment	100 Mcr	20 Mcr	20 Mcr	5 Mcr
Investment costs	920	185	185	46
Labour	50	50	50	25
Total costs/ton of steel	1387	664	476	647
b. Large-scale production in an 1 Mt/year plant				
Ore concentrate	130	130	130	130
Fuels, electr. and oxygen	257	293	11	445
Lime	30	6	100	1
Investment	1000 Mcr	800 Mcr	1000 Mcr	400 Mcr
Investment costs	74	59	74	29
Labour	25	40	50	25
Total costs/ton of steel	516	528	365	630

Table 9-11

Energy costs per ton of steel, 2025.

	Blast furnace with sintering of ore		Wiberg process with sintering of ore		Injection smelting reduction of magnetite		Plasma reduction of magnetite	
	GJ	cr	GJ	cr	GJ	cr	GJ	cr
Ore reduction								
Coke	15.8	509	3.9	126				
Coal					99	1445		
Gas			2.6	88	-75	-2550		
H_2							5.6	375
Electricity	0.5	27	3.3	178			6.3	339
Oxygen (impure)					(2200 Nm^3)	330		
Sub total		580		392		-775		-714
Refining								
Oxygen (pure)	(58 Nm^3)	34				13		
Coal							0.4	6
Electricity			5.4	291	1.0	54	1.1	59
		614		683		-708		779

Table 9-12

Total steel making costs in 2025 for small-scale and large-scale production (cr per ton of metal).

a. Small-scale production in a microplant as part of a production line in a workshop
(1 ton/hour = 8 kt/year)

	Blast furnace process	Wiberg process	Injection smelting reduction	Plasma with hydrogen
Ore concentrate	130	130	130	130
Fuels, electr. and oxygen	614	683	-708	779
Lime	30	6	100	1
Investment	100 Mcr	20 Mcr	20 Mcr	5 Mcr
Investment costs	920	185	185	46
Labour	50	50	50	50
Total costs/ton of steel	1744	1054	-243	1006
b. Large-scale production in a 1 Mt/year plant				
Ore concentrate	130	130	130	130
Fuels, electr. and oxygen	614	683	-708	779
Lime	30	6	100	1
Investment	1000 Mcr	800 Mcr	1000 Mcr	400 Mcr
Investment costs	74	59	74	29
Labour	25	40	50	25
Total costs/ton of steel	873	918	-354	964

9.5 Developments until the year 2025

9.5.1 Future production philosophy

The steel industry supplies a large number of different products at present, but developments so far have been characterized by a tendency towards greater standardization. This is partly due to the historically big demand and short supply of steel. The steel market has therefore been very much a seller's market, where the industry has been able to produce steel in volumes determined by the existing production processes. The increased demand for more varied products from a more highly developed manufacturing industry has been met by offering standardized semi-finished products, which are further processed by other manufacturing industries.

By standardizing its products, the steel industry has been able to adjust its output to the limitations set by a slow reduction process, and casting and metal-working in inflexible units which cannot simply or quickly be adapted to varying product dimensions. The result of this has been a concentration of production to fewer and larger units.

The production of standardized semi-finished products in large numbers is a rational mode of production demanding fewer man-hours per item, but it also means losses of raw materials and fuels when the semi-finished products are processed to the finished products in later manufacturing steps. This development has been stimulated by the system of taxation which has made labour very costly, while at the same time raw materials and fuels have largely escaped taxation.

During the period 1925 - 1975, Swedish society has become increasingly industrialized in order to be able to produce a greater number of products. The main objective has been to meet the quantitative shortage of products. Today many factors suggest that we are approaching a saturation point where the quantitative shortage of products will no longer be a major problem. This will inevitably lead to a situation where production will be geared to quality and product performance rather than quantity. This will probably necessitate a revaluation of current production structure. Developments in the next 50-year period, from 1975 to 2025, may be significantly different from those between 1925 and 1975.

The present taxation system has been used as a tool to stimulate a trend towards increased productivity, that is an increased amount of product per man-hour. If this increased productivity does not remain the major goal, there will be an incentive for considering other taxation systems, geared to the new goals of society.

There are thus strong reasons for expecting a change in the set of factors that have stimulated the trend towards large-scale production of steel in the form of standardized semi-finished products. This will probably mean that society must adapt to a changing scenario marked by periods of "steel crisis" situations, with perhaps 5 - 15 year intervals.

It is of course impossible to foresee what production will be like in 2025. There will be several changes in the trends between now and 2025, as well as adjustments to situations which can hardly be foreseen today. In order to arrive at some sort of a meaningful scenario for the year 2025, we are forced to make a number of simplified assumptions, such as the assumption that the basic factors motivating the production of steel will not change, and that a section of the present production will remain unchanged whereas the remainder will be changed and developed in the direction which at present seems most probable.

If the basic factors determining present-day production remain unchanged with the sole exception of changes in the prices of different energy carriers according to the scenario that this study is based on, there is no reason to expect any use of hydrogen in the Swedish steel industry. If development towards fewer and larger units continues to be stimulated, there will be relatively good possibilities for controlling the problems of slow coal-based processes. Concentrated facilities simplify the employment of relatively extensive measures for controlling environmental problems. Since in this study the availability of coal has been assumed to be large enough to warrant a relatively low coal price during the period, there is no reason to expect that hydrogen will be able to compete with coal in the steel industry.

In countries where the most commonly used reducing agent is natural gas, it seems appropriate to consider hydrogen as a serious alternative when the availability of NG decreases in the foreseeable future. For the coal-based Swedish steel industry, it is possible that it might become more difficult to import coal. This has not been assumed in this study, but if it should happen, the problem might be overcome by returning to an increased used of charcoal.

However, if it is assumed that part of the steel production, e.g. one half in the year 2025, will be carried out in small units where production is more geared to the manufacture of products, and where this shift is more important than the cost of the reductant, then hydrogen may be a potential reductant and fuel in such plants. It might be possible to develop other fast processes which can be run on a small scale. These could use coal, biomass, peat etc for the reduction. However, if hydrogen becomes easily available, it seems likely that hydrogen reduction will be competitive for this type of production.

If the demand for syngas for the synthesis of liquid fuels, e.g. methanol, becomes very extensive, and if the exhaust gases from reduction processes, e.g. injection smelting recution, can be used for this purpose, then the combination of coal gasification/liquefaction and steel production will become competitive in medium or large-scale operation. In such a situation, the demand for synthesis gas rather than the demand for steel determines the production capacity. Under these circumstances, it might be possible to produce iron at such a low cost that small-scale ore reduction, tied to the manufacture of finished products, would only be viable in very special cases.

For the following calculations the assumption is made that one half of the steel production in 2025 will be based on hydrogen reduction in plasma reactors. It must be stressed, however, that for this situation to occur the following conditions must be met:

- The demand structure and the economic regulatory measures, such as taxes, must be changed so as to facilitate small-scale steel production coupled with subsequent manufacturing process.

- The demand for syngas for liquid fuel production must continue to be small by comparison with the demand for steel.

9.5.2 Production quantity

It is at least as difficult to foresee the amount of steel that will be needed in the year 2025 as it is to foresee the production methods that will be used. The trends that were observable during the past decades occurred within an expanding society, which can be expected to take new directions now that the former goals have been reached. Urbanization no longer requires the rapid growth of cities and communications, the industrial need for heavy equipment is no longer insatiable, the expansion of world trade no longer requires a rapid increase of shipping capacity etc. There are therefore reasons for believing that the demand will be saturated in many sectors. An increased demand for steel will then be unlikely unless new areas for using steel can be found. Present demand trends offer no clues as to such new areas.

In this study, the production in the year 2025 is assumed to be 125 % of the production in 1977, i.e. 5 Mt/year, or slightly less than the 1974 production of 6 Mt. The assumption does not imply that this production volume is more likely than any other. It has been chosen as an example of a production volume that can satisfy an almost constant steel consumption. It should be observed that a substantial part of the steel produced today is turned to scrap before the final manufacturing step. This scrap is recycled and remelted, which of course requires less energy than ore reduction but still represents a considerable loss of resources. If steel is produced in a way that is better adjusted to the finished product, then less scrap is obtained and less recycling is required. Thus a production of 5 Mt in the year 2025 might well mean a greater availability of steel in the form of finished products than was the case in 1974 with a total production of 6 Mt of steel. In the assessment of fuel requirements in 2025 (Tables 9-10 and 9-12), a decrease in scrap recycling was taken into account.

9.5.3 The period 1978 - 2025

The Swedish steel industry is today engaged in a difficult adjustment to the present demand situation. When this has been completed, a period is to be expected when industry will capitalize on the advantages gained. A new comprehensive structural change is not likely before the end of the 1980's.

There is no basis for an assessment of how rapidly changes can occur after 1990. It is therefore not meaningful to attempt to give a detailed description of possible crisis situations and periods of change around the coming turn of the century. No such description would have more credibility than a simple assumption, such as:

- No change of the situation until 1990, and thereafter a constant development of the postulated situation in the year 2025.

This is the development assumed in this study.

9.5.4 Hydrogen demand in the year 2025

The assumptions made lead to a structure where 2.5 Mt of steel are produced in large plants and 2.5 Mt in small installations linked to further manufacturing.

All production in the large plants is assumed to be based on methods in use today, that is in integrated plants with blast furnaces and a 50 % scrap base. The small-scale production is assumed to be entirely based on ore as the raw material, owing to quality considerations and shortage of scrap. The reduction will be carried out in plasma reactors with hydrogen as the reductant. Consumption figures are summarized in Table 9-13.

The entire production requirements of electrical energy and fuels are given in Table 9-14.

Table 9-13

Reductant and energy for steel production (GJ/ton steel).

	1974 (partly older installations) GJ/ton steel	2025 GJ/ton steel
Large units (50 % scrap):		
Coke	8.3	10.6
Oil	6.8	0.2
Electricity	4.0	3.0
Total energy	19.1	13.8
Small units		
Hydrogen	-	5.6
Electricity	-	6.3
Total energy	-	11.9

Table 9-14

Energy requirements for ore reduction.

	1974 (6 Mt steel) PJ	2025 (5 Mt steel) PJ
Coke	50	27
Oil	41	1
Hydrogen	-	14
Electricity	24	23
Total	115	65

Notice that in Tables 9-13 and 9-14 it has been assumed that most of the oil is replaced by coke, whereas in Table 9-11 and 9-12 the use of oil in blast furnaces is assumed to be the same as today.

Thus, on the basis of the assumptions made, the demand for hydrogen in the steel industry will be 14 PJ in the year 2025, i.e. approximately 0.1 Mt of hydrogen, which is about equivalent to the production capacity of a large plant (0.14 Mt H_2/year). If many small-scale steel factories are to be supplied, then there must be an efficient distribution system for hydrogen. The increase in the demand for hydrogen is assumed to start in 1990 and to progress according to the graph in Figure 9-17.

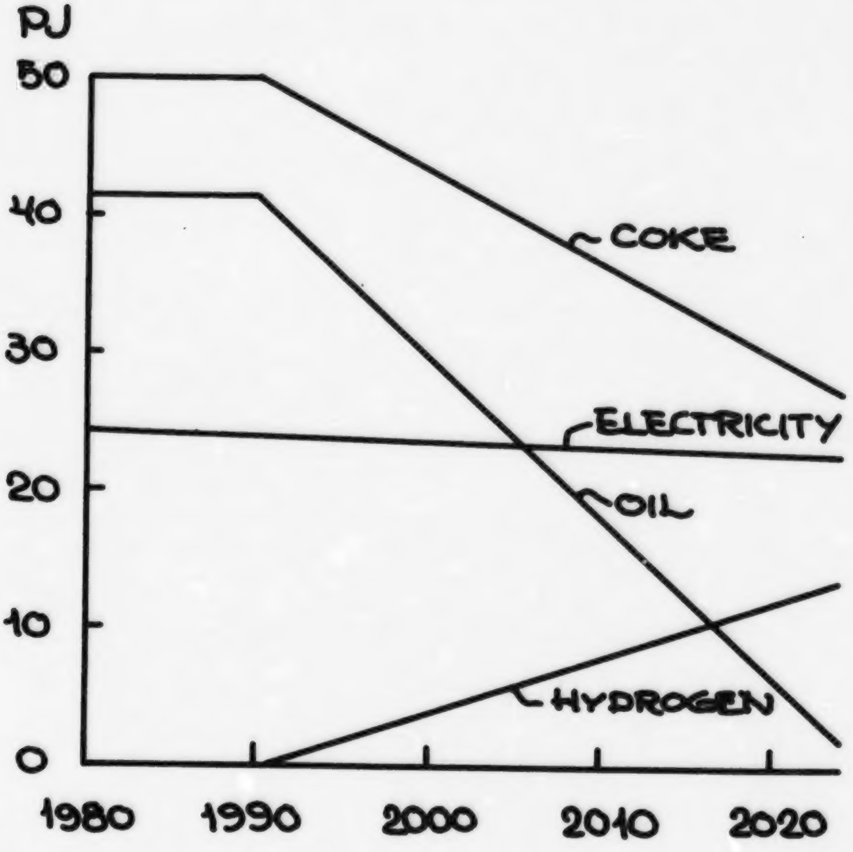

Figure 9-17

The demand for fuels and electricity for reduction purposes, 1978 - 2025.

In the three scenarios considered in this study, different assumptions regarding the availability of various energy carriers are used. However, in each case the same price scenario is assumed to be valid for all energy carriers considered. They are also assumed to be available to the extent required by the consumer. The development within the steel production sector is mainly governed by factors which are independent of those that govern the establishment of the scenarios used in the study. It can therefore be assumed that the steel producers employ the same methods in each scenario of this study.

9.5.5 The future demand for oxygen

In 1974, Sweden produced 0.5 Mt of oxygen with a total value of 87 Mcr, i.e. 174 cr/ton. The import was 1.53 kt at a total cost of 550 kcr, i.e. 360 cr/ton, and 2.2 kt was exported.

If we assume that the demand for oxygen will increase at the same rate as that of the total production according to the economic scenario (Chapter 3), i.e. 1.6 % per year, then the demand will be 0.8 Mt oxygen by the year 2005. If we assume a price of 100 cr/ton, this oxygen will have a value of 80 Mcr. If it is produced by electrolysis, 100 kt hydrogen will also be obtained, i.e. 15 PJ. The oxygen price will thus reduce the hydrogen cost by 5 cr/GJ.

If the use of oxygen in the iron and steel industry increases so that most of the fuel is burned in oxygen instead of in air by the year 2025, if oxygen bleaching replaces chlorine bleaching in the paper and pulp industry and if oxygen is used for some other processes, the demand for oxygen might increase to about 6 Mt by the year 2025. If we assume a price of 150 cr/ton, the production of 750 kt of hydrogen by electrolysis could be credited with the income from the oxygen, i.e. about 8 cr/GJ.

If the use of methanol as a substitute for petrol increases, the demand for oxygen might increase considerably. It is also possible that by the year 2025 pollution abatement will lead to a situation where open combustion in smaller industries and homes becomes impossible. One way of producing heat might then be the exhaust-free combustion of pure oxygen and pure hydrogen to water without any NO_x production. This is discussed further in other chapters.

9.5.6 Investments

The total investments of the steel industry in new installations and inventories are approximately 1 Gcr/year at present.

If half of the existing raw steel capacity is successively replaced by plasma units, starting in 1990, the need to replace out-of-date or worn out equipment up to 2025 will be replaced by the need to invest in plasma reactors and equipment for further manufacturing.

The specific investment, i.e. the investment per ton of production capacity, is considerably lower for a plasma system than for other alternative methods. It is probably less than half of that for a blast furnace system. Another important reason for switching to a plasma reduction process is the possibility of intermittent production that it offers. If this possibility is fully utilized with a daily operation time of 8 hours, the installed capacity must be tripled in order to obtain the same annual production rate.

Thus it is likely that the decreased investment costs will be balanced by a higher capacity requirement. Given the assumed rate of plasma system introduction, annual investments in the steel industry can be regarded as approximately constant over the period, i.e. ~ 1 Gcr/year.

9.6 Non-ferrous metals

The electrochemical potential of a metal gives a measure of the strength of the bond between the metal and its non-metallic ore ligand. If the reduction potential of a metal electrode is positive with respect to the hydrogen electrode, then hydrogen is more strongly bonded to the non-metallic part, e.g. oxygen, than is the metal. Such a metal is usually easy to reduce with hydrogen.

If a metal electrode is negative with respect to the hydrogen electrode, then the bond between hydrogen and oxygen is weaker than that between the metal and oxygen. Nevertheless, some H_2O will be produced if the metal oxide is kept in a hydrogen atmosphere and the system is allowed to reach equilibrium. If instead the water formed is continuously removed from the system, new water molecules will be produced to restore equilibrium, thereby reducing the metal oxide.

If a metal electrode has a high negative potential with respect to the hydrogen electrode, the H_2O formed in equilibrium with H_2 and metal oxide constitutes a very small part of the system. For such a system it is difficult to remove enough H_2O to keep the system in non-equilibrium.

The standard reduction potentials, given in Table 9-15, show that in the case of oxidic ores, hydrogen is an excellent reducing agent for Ag and Cu and still useful for Pb, Sn and Fe. However, it is very difficult to keep the water pressure at the low levels that are necessary for the reduction of Al, Cr, Mg, U and Zn.

Another problem is that for some metals the available minerals are sulphides instead of oxides. Removal of sulphur with H_2 means the production of highly poisonous H_2S. It will probably be impossible to use such processes for metal production.

Table 9-15

Standard reduction potentials with respect to the hydrogen electrode for some metals (14).

Reaction	Potential Volt	Reaction	Potential Volt
$Fe^{2+} + 2e \rightarrow Fe$	-0.41	$Ag^{+} + e \rightarrow Ag$	0.80
$Fe^{3+} + e \rightarrow Fe^{2+}$	0.77	$Mg^{2} + 2e \rightarrow Mg$	-2.38
$Cr^{2+} + 2e \rightarrow Cr$	-0.56	$Pb^{2} + 2e \rightarrow Pb$	-0.12
$Cr^{3+} + e \rightarrow Cr^{2+}$	-0.41	$Sn^{2+} + 2e \rightarrow Sn$	-0.14
$Al^{3+} + 3e \rightarrow Al$	-1.71	$Sn^{4+} + 2e \rightarrow Sn^{2+}$	0.15
$Cu^{+} + e \rightarrow Cu$	0.52	$U^{3} + 3e \rightarrow U$	-1.8
$Cu^{2} + Cu^{+}$	0.16	$Zn^{2+} + 2e \rightarrow Zn$	-0.76
$Cu^{+} + 2e \rightarrow Cu$	0.35		

In 1974, Sweden produced about 0.5 Mt of non-ferrous metals. About 0.25 Mt were produced from scrap and 0.25 Mt from ore reduction. The quantitites of the most important metals are shown in Table 9-16 (2).

Table 9-16

Production of non-ferrous metals in 1974, tons.

	By reduction	From scrap	Total
Silver			187
Platinum			0.06
Copper	59000	129000	188000
Nickel			4000
Aluminium	122000	69000	191000
Lead	45000	28000	73000
Zinc			1000
Tin			2000
Magnesium & beryllium			23
Tungsten, molybdenum & tantalum			17

Small quantitites of hydrogen are used in the production of uranium fuel elements. The quantities are, however, so small that even a drastic increase in nuclear power production would not lead to any noticable increase in the total hydrogen consumption.

For some metals, such as Al, it is very unlikely that H_2 could be used as a reductant. Even if it were possible to use H_2 for the entire Swedish requirement of non-ferrous metals, this would mean an H_2 consumption that is smaller than the margin of error for the possible H_2 consumption in the iron and steel industry.

9.7 Summary

In Sweden, the possible future reductants for domestic iron ores are coke, coal, charcoal, biomass and hydrogen. If the present production structure is maintained, that is if the iron and steel industry produces semi-finished standardized products in large production units, it is very unlikely that hydrogen reduction can compete with the other alternatives.

If the production structure is changed towards an integration of ore reduction with the manufacturing of finished products, it is essential that the reduction process should be fast and require only small investments, that the pollution problem should be easy to handle, and that the process can be turned on and off during the day. All these requirements can be met by a plasma process with hydrogen as reductant. There are of course other alternatives, e.g. a plasma process with coal as reductant, but so far the hydrogen-based plasma process seems to be competititive in this situation.

A switch to the use of plasma reactors with hydrogen as the reductant has the following advantages and disadvantages:

Advantages	Disadvantages
Low investment cost, even for small-scale processing	High production cost, high total cost
Rapid process, may be operated intermittently	Cannot be combined with gas production*
No problems with exhaust gases	

* Combination with gas production is possible if the plasma reduction is carried out with coal, peat, biomass etc as the reductant.

A coordination of steel production and the manufacture of the finished steel products may decrease the generation of steel scrap sufficiently to balance the higher cost of steel production in small hydrogen plasma reactors.

Public and/or government demands for a successive transition from shiftwork to daytime work may force industry to adapt processes which are better suited to intermittent operation. A change from the present system of taxing labour to taxation of other production factors, such as raw materials and fuels, may create a greater interest in a coordination of ore reduction with the further processing of raw steel to yield finished products.

It is assumed here that the production of steel in 2025 will be 5 Mt, 2.5 Mt of which will be produced by existing methods and 2.5 Mt with plasma reduction using hydrogen as reductant. The plasma reactors are assumed to be small units, which are integrated with the manufacturing process that yields the finished products. The introduction of plasma reactors is assumed to commence in 1990 and proceed at an even rate until the year 2025. The need for hydrogen in steel-making will then be

	1985	1995	2005	2015	2025
kton	-	15	43	73	100
PJ	-	2.1	6.2	10.4	14.5

The investments required for this transition will be covered by the investments otherwise required to maintain the production structure. In other words, the change will not mean any greater investments than those required to maintain the present capacity using unchanged production methods, i.e. about 1 Gcr/year (1978 cr).

Hydrogen may also be used as a reductant in the production of metals other than iron, and as a fuel in other metal treatment processes. Such uses of hydrogen are likely to occur to an extent which is smaller than the margin of error in the above estimate of the need for hydrogen in steel production.

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10. PEAK POWER GENERATION

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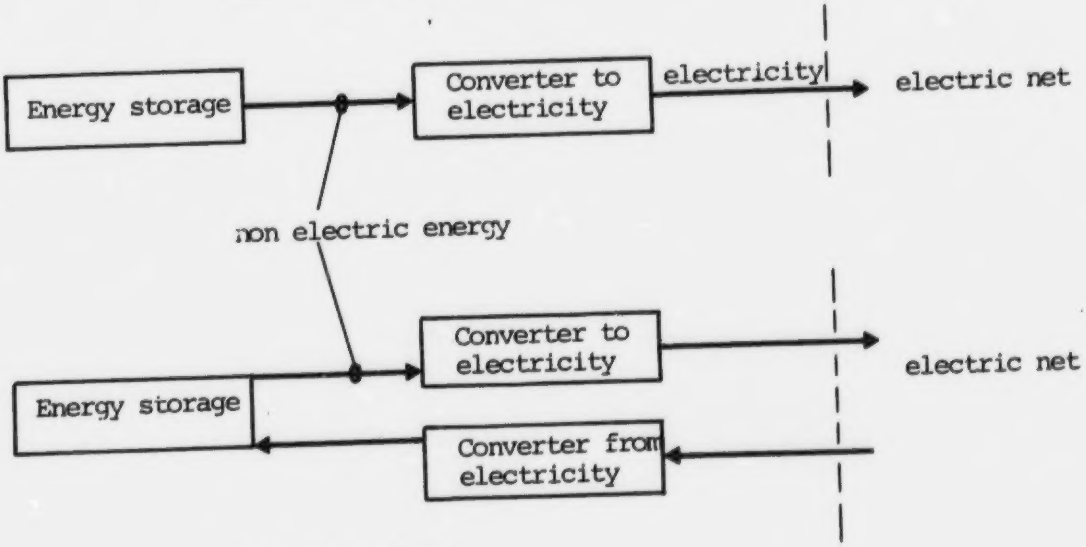
10.1 Introduction

Electricity cannot be stored at reasonable costs today and thus the electricity must be produced at the same time as it is consumed. Research work is, however, being carried out in order to evaluate the possibility of storing electricity with the aid of superconducting material (7). In the foreseeable future the production system must be dimensioned so that it can cover the need for electricity even during those hours of the year with maximum load. An optimal production system for electricity must include different types of production machines, from base load plants suited for long term operation to peak power plants for short annual operating times.

	Investment costs	Running costs
Peak load	Low	High
Base load	High	Low

During certain parts of the year, the base load plants may be able to produce an excess of electricity above the actual demand. In such a case it is often favourable if this excess electric energy can be transformed into some other form of energy and then converted back to electricity in a peak load plant when the electricity demand is large. Peak load plants can therefore be divided into storage and non-storage plants according to the following sketch:

Non-storage plant


Energy storage
Converter to electricity
electricity
electric net
non electric energy
Converter to electricity
electric net
Energy storage
Converter from electricity

Storage plant

If the energy produced annually in a power plant is divided by its maximum power output, the utilization time is obtained. In this study, a peak power plant is defined as a plant with a utilization time below 2000 h/year (7.2 Ms/year).

Table 10-1

Technical data of present peak power plants.

		A	B	C	D	E	F	G
		Conventional pump power stations	Pump power stations with underground storage	Air magazine power station with gas turbine	Gas turbine power station		Peak power condensing plant	Combined plant Gas/steam turbine
					Industrial type	Jet engine type		
1 Block power	MW	200 - 400	250	230	90	75	250	250
2 Station power	MW	200 - 1 000	2-4x250	1-4x230	2x90,6-12x90	2x75,6-12x75	2-4x250	2-4x250
3 Utilization time	h/year	-	-	500	500	500	1 500	1 500
4 Magazine output		5x12 h/week	10 h/24 hours	10 h/24 hours	-	-	-	-
5 Corresponding input		5x6+2x24 h/week	12 h/24 hours	ca 11 h/24 hours	-	-	-	-
6 Electricity consumption during loading	MW/block		240	150	-	-	-	-
7 Time from start to full load		180 sec	180 sec	8-20 min	8-20 min	2-4 min	2.5 h	8-20 min, 1 h
8 Time for interrupting loading		Instantaneous	Instantaneous	Instantaneous	-	-	-	-
9 Magazine volume per block	10^6 m^3	-	2.4	0.5	-	-	-	-
10 Level difference over/under magazine	m		450	250	-	-	-	-
11 Efficiency at full load and continuous power	%	80	80	Not suitable characteristics	27-34	27	33	46
12 Part load efficiency		Good	Good	Good	Less favourable	Less favourable	Good	Good
Fuel and electricity consumption (for electricity generation)								
13 Heavy oil	m^3/MWh	-	-	-	-	-	0.28	-
14 Light oil	m^3/MWh	-	-	0.15	0.31	0.37	-	0.22
15 Electricity	MWh/MWh	1.25	1.25	0.76	-	-	-	-
Annual fuel consumption/block for assumed utilization time								
16 Heavy oil	m^3/year	-	-	-	-	-	105 000	-
17 Light oil	m^3/year	-	-	17 500	14 000	14 000	-	80 000
18 Assumed volume of fuel storage	m^3/year	-	-	100	300	300	[illegible]00	400
19 Cooling water	m^3/MWh	-	-	25	0-30	0	140	55-60
20 Process sweet water	m^3/MWh	-	-	-	-	-	0.04-0.4	0.01-0.1
21 Cooling water temperature rise	°C	-	-	2-3	20	-	8-10	8-10
22 Ground area requirement for station (block)	ha/number of blocks	-	35/2	70-100/4	3/2,20-25/12	3/2,20-25/12	15-25/4	15-25/4
23 Ground area requirement for oil storage in ground	ha/number of blocks	-	-	-	1-2/2	1-2/2	15-25/4	15-25/4
24 Necessary ground conditions		Good	High demands	High demands on rock quality	Good	Good	Good	Good

10.2 Alternative peak power production methods today

At present, the following seven different types of peak power plants are considered in Sweden:

- conventional pump power
- pump power with underground storage
- air magazine power station with gas turbine
- gas turbine, industrial type
- jet engine type gas turbine
- peak power condensing plant
- combined gas/steam turbine plant

Technical, economic and environmental data, taken from (1), are presented in Tables 10-1 to 10-3, respectively. The data are adjusted to the 1978 value of the Scr, a real interest of 4 %, a depreciation time of 25 years and the fuel cost scenario of this study, Table 10-4.

Table 10-4

Assumed prices of energy at the peak power plant site, cr/GJ*.

Year	Energy type	At production site or in port	Transport (100 km)	Storage	Total
1978	Electricity	24.4	7.2		31.6
	Light fuel oil	19.5	0.5		20.0
	Heavy fuel oil	11.0	0.5		11.5
2005	Electricity	38.9	7.2		46.1
	Light fuel oil	36.5	0.5		37.0
	Heavy fuel oil	22.0	0.5		27.0
	GH_2	51.0	0.6	0.8	52.4
2025	Electricity	53.8	7.2		61.0
	Light fuel oil	61.4	0.5		61.9
	Heavy fuel oil	33.6	0.5		34.1
	GH_2	62.0	0.6	0.8	63.4

* 1 GJ = 277.8 kWh.

Table 10-2

Economic data adjusted according to the economic rules of this study (1978 cr).

	A Conventional pump power stations	B Pump power stations, underground	C Air magazine power station, gas turbine (efficiency 20 %)	D Gas turbine, industrial type	E Power station, jet engine type	F Peak power condensing plant	G Combined gas/steam turbine plant
Investment costs cr/kW	800 - 1200	1200	1100	1200	1100	2000	1500
Fixed annual cost cr/kW, year							
Capital costs (4 %, 25 year)	50 - 70	76	70	78	70	127	95
Maintenance	5	6	5	8	8	22	12
Fixed fuel costs; rent of stored fuel. Average fill up (80 %)	-	-	10	20	20	48	30
Sum	55 - 81	82	85	106	98	197	137
Running costs cr/kWh							
Fuel, excluding fuel for starting	-		0.103	0.206	0.229	0.108	0.135
Electric energy (price of "night electricity" = half the price of Table 10-4)	0.055		0.055	-	-	-	-
Running maintenance	-		0.003	0.006	0.023	0.005	0.006
Sum	0.055		0.161	0.212	0.252	0.113	0.141

Table 10-3

Environmental effects.

		A + B	C	D	E	F	G
		Pump power station	Air magazine gas-turbine station	Gas turbine power stations		Peak power condensing plant	Combined gas/steam turbine plant
				Industrial type	Jet engine type		
Water recipient							
Thermal	MW heat/MW el	-	0.6	0.7	0	1.6	0.7
Regulations necessary		Small, though depending on recipient and magazine magnitudes	Small, though depending on recipient and magazine magnitudes	-	-	-	-
Air recipient							
Emissions of SO_2	kg/GJ el	-	0.6 1)	1-1.3 1)	1.3 1)	1.5 2)	0.9 1)
Emissions of NO_x	kg NO/GJ el	-	0.3-1	0.6-1.5	0.6-1.5	0.3-0.6	Somewhat less than for gas turbines
Heat in exhausts	GJ/GJ el	-	1	2-3	2-3	0.2	0.4
Sound emissions							
(At 200 m distance)	dB(A)/number of blocks	Small	Somewhat smaller than large gas turbine power stations	50/2 55-60/12	50/2 55-60/12	55-60/4	
Fuel transport		- None	As smaller gas turbine plants	Smaller units: Road and rail transports Larger units: Ship transport necessary		Ship transports necessary	As peak power condensing plants
Landscape		Excavated rocks might disturb the view	Excavated rocks might disturb the view	Small units: Small or no problems Larger units: Conflict with seashore localization		Buildings often high	As small gas turbine plant

1) 0.8 % sulphur in fuel.

2) 1 % sulphur in fuel.

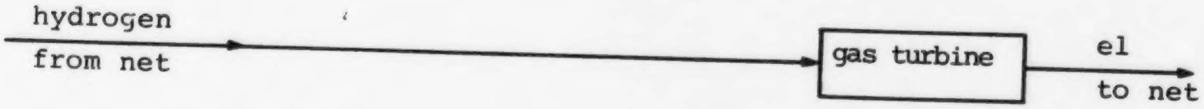
10.3 Hydrogen peak power plants

As with all other peak power plants, hydrogen fuelled plants can be divided into storage and non-storage types. Hydrogen plants can also be divided into groups classified after the type of energy converter that is used.

The four types of peak power plant H - K considered here are illustrated schematically in the following figure. The most important parameters used for the calculations are listed in Table 10-5.

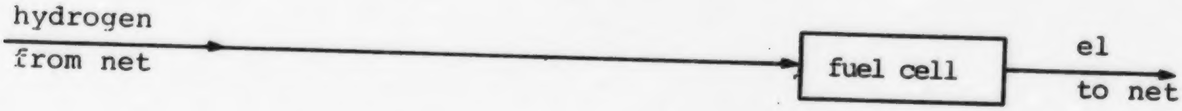
Non storage/gas turbine (alternative H)

Ref


hydrogen
from net
gas turbine
el
to net

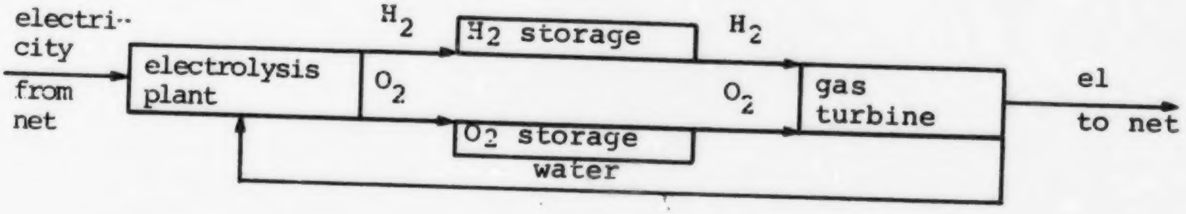
2

Non storage/fuel cell (alternative I)


hydrogen
from net
fuel cell
el
to net

3

Storage/gas turbine (alternative J)


electricity
from net
electrolysis plant
H_2
H_2 storage
H_2
O_2
O_2
O_2 storage
water
gas turbine
el
to net

Storage/fuel cell (alternative K)

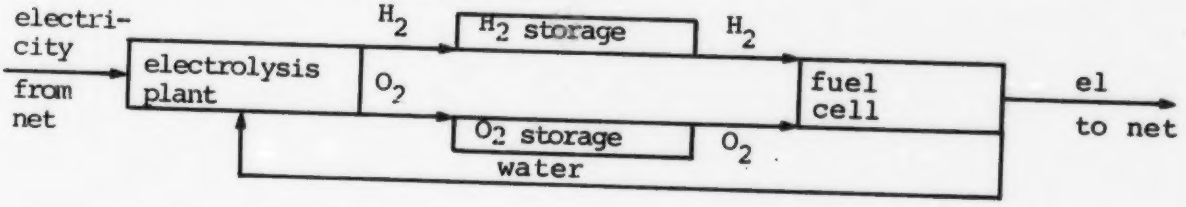

electricity
from net
electrolysis plant
H_2
H_2 storage
H_2
O_2
O_2 storage
O_2
water
fuel cell
el
to net

Table 10-5

Assumed parameters for the hydrogen alternatives (technical level 2005).

Alternative	Total investment costs cr/kW	Efficiency of the whole process %
H	1200 Same value as for industrial gas turbine	50 (2)
I	1400	50 (5) and Chapter 12
J, K	Estimated in this study	42.5 (6) (86 % in electrolysis)

Table 10-6 compares the economy of the hydrogen alternatives with the conventional alternatives A-G discussed earlier. Figure 10-1 shows the cost of producing 1 kW power as a function of the utilization time for all the alternatives A - K.

10.4 Conclusions

As the capital costs of the storage hydrogen alternatives are higher than for the pump power stations, the efficiencies of the hydrogen alternatives must be raised above those of the pump power stations if they are to become competitive with these in 2025. Such an increase in efficiency of the hydrogen cycle from 2005 to 2025 is highly improbable. Hydrogen is therefore not expected to be used in Sweden for peak power production during the period under consideration.

Table 10-6

Economic data for alternatives A - K; year 2005; annual operation time 700 h.

	A	B	C	D	E	F	G	H	I	J	K
Investment cr/kW output	1000	1200	1100	1200	1100	2000	1500	1200	1400	2500	2800
Total fixed cost cr/kW·year	68	82	85	106	98	197	137	98[1]	110	158	176
cr/kWh	0.097	0.117	0.121	0.151	0.140	0.256	0.196	0.140	0.157	0.226	0.251
Running costs cr/kWh											
Off-peak electricity	0.080	0.080	0.080							0.188[2]	0.188[2]
Light oil			0.222	0.443	0.493						
Heavy oil						0.295	0.290				
Hydrogen								0.377[2]	0.377[2]		
Maintenance	-	-	0.003	0.006	0.023	0.005	0.006	0.006	0.006	0.022	0.40
Total running cr/kWh	0.080	0.080	0.332	0.449	0.516	0.300	0.296	0.383	0.383	0.210	0.228
Total cost cr/kW·year	124	138	317	420	459	386	344	366	378	305	336
cr/kWh	0.18	0.20	0.45	0.60	0.66	0.55	0.49	0.52	0.54	0.44	0.48

1) As alternative D - not taking the interest on stored fuel into account.

2) The efficiency of a gas turbine or a fuel cell has been assumed to be 50 %. The efficiency of an electrolysis plant has been assumed to be 86 %.

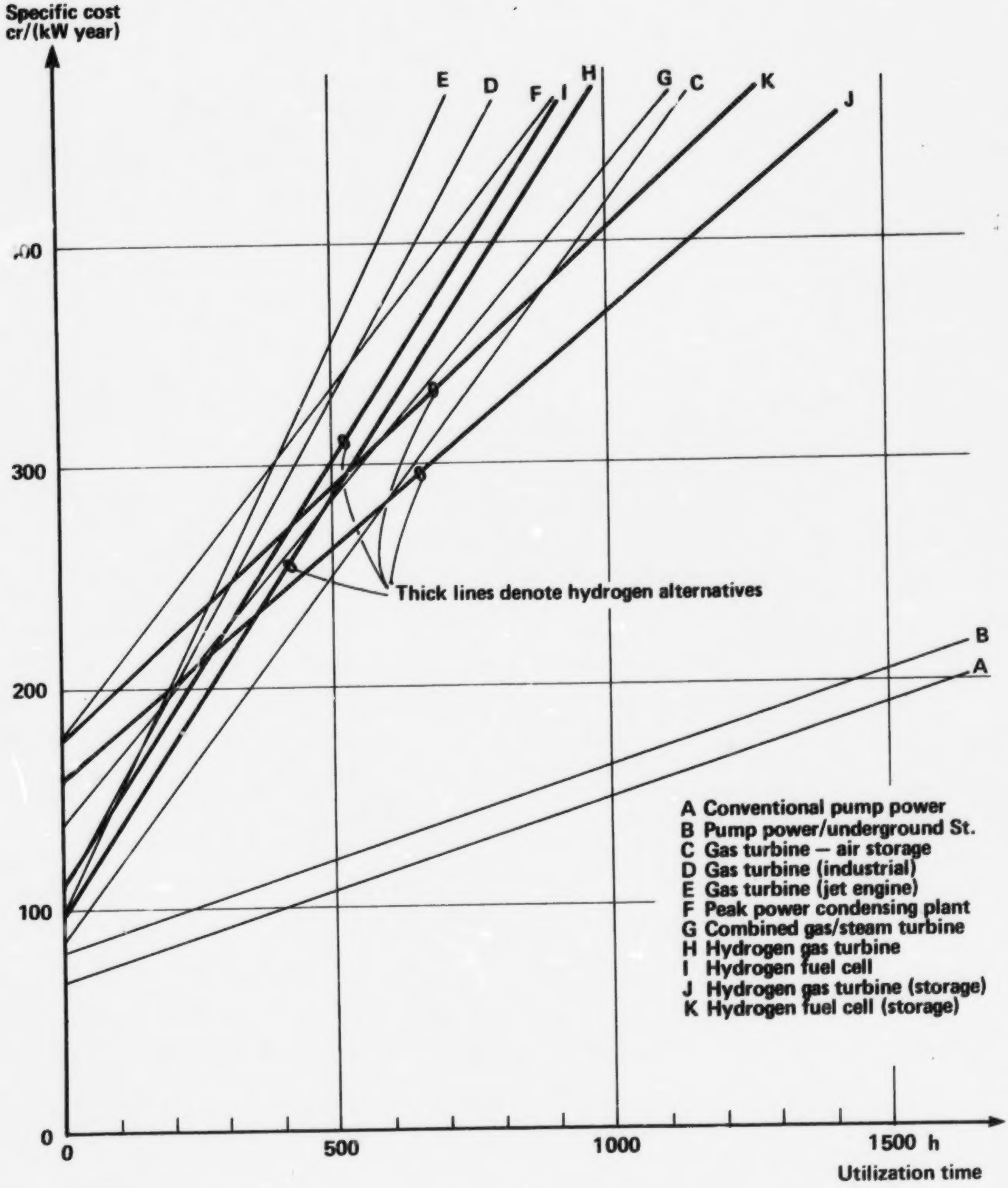


Figure 10-1

Cost of different peak power plants in 2005, 4 % real interest, 25 years' depreciation time.

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10-12

11. RESIDENTIAL AND COMMERCIAL HEATING

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11.1 Background

At present Sweden has about $8.2 \cdot 10^6$ inhabitants (1) living in $3.5 \cdot 10^6$ private houses or flats (2). The energy consumption in 1975 for heating and other purposes was about 80 TWh (288 PJ) for these houses and flats (3). Other buildings, offices, etc, consumed about 43 TWh (155 PJ) (3). The total energy consumption for space neating was therefore 123 TWh (443 PJ).

As the number of persons per flat or house is decreasing, approaching on average 2 persons per flat in the year 2000, and simultaneously the area of each flat or house is increasing, it might be expected that the energy consumption would increase rapidly. However, over the years 1920 - 1960, the specific consumption of energy has been decreasing by about 1 % per year (2). In view of the energy shortage in the future, the trend of a decreased specific energy consumption can be expected to accelerate. The scenario description of this study therefore assumes that a very modest increase of 0.1 % per year total net consumption will take place. This will result in a total net energy consumption for heating flats, private houses and other buildings of about 129 TWh in the year 2025.

The structure of the energy supply for heating in 1975 is shown in Table 11-1.

11.2 Technical aspects of hydrogen as a heat source

11.2.1 Direct combustion

Hydrogen can easily be burned in atmospheric burners (5). Some adjustments have to be made to the conventional type of gas burner used today, Figure 11-1.

Table 11-1

Energy supplied for heating in 1976 (4).

	Private houses and flats %	Other buildings %
Coal	0.3	
Kerosene	0.2	0.7
Light oil	50.1	38.6
Heavy oil	13.2	24.8
Gas	1.0	0.4
District heat	13.4	10.4
Electricity	21.8	25.1

11.2.1.1 Flashback and blowoff

When the gas flow is slower than the burning velocity of the flame, flashback occurs. The hydrogen burning velocity is greater than the burning velocity of all other gas fuels. To prevent flashback in hydrogen burners, the gas velocity must therefore be greater than that conventionally employed.

Blowoff occurs when the gas velocity is faster than its burning velocity. The flame front then moves downstream until either the gas velocity has slowed down and become equal to the burning velocity or the flame is extinct.

Both flashback and blowoff phenomena are dependent on the following factors:

Gas flow	q $[m^3/s]$
Burner port radius	R [m]
Gas fraction	c [1]

The boundary velocity gradient can be defined as:

$$v_b = 4\ q/R^3\ [s^{-1}]$$

Figures 11-2 and 11-3 from (5) show how flashback and blowoff depend on v_b and c.

To overcome the problems of flashback, the primary air mixing could be abandoned and compensated for by an increased secondary air mixing. Another way is to increase the velocity of the hydrogen stream.

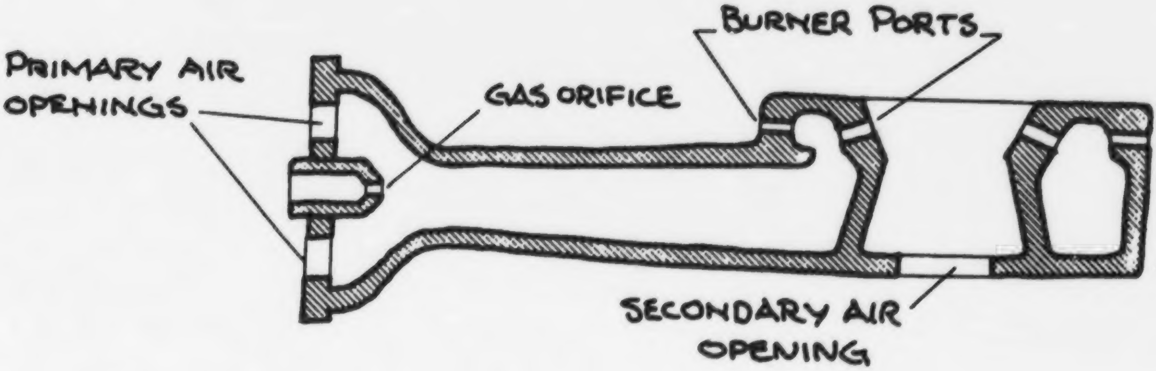


Figure 11-1

Principal parts of a typical atmospheric burner (5).

11.2.1.2 Burner emissions

The only hazardous emission from a hydrogen-air flame consists of nitrogen oxides. For the same heat release, the NO_x emission is about 1.5 - 3 times higher than that of natural gas (5). By limiting the flame temperatures, for instance by water spraying, NO_x emissions can be kept low.

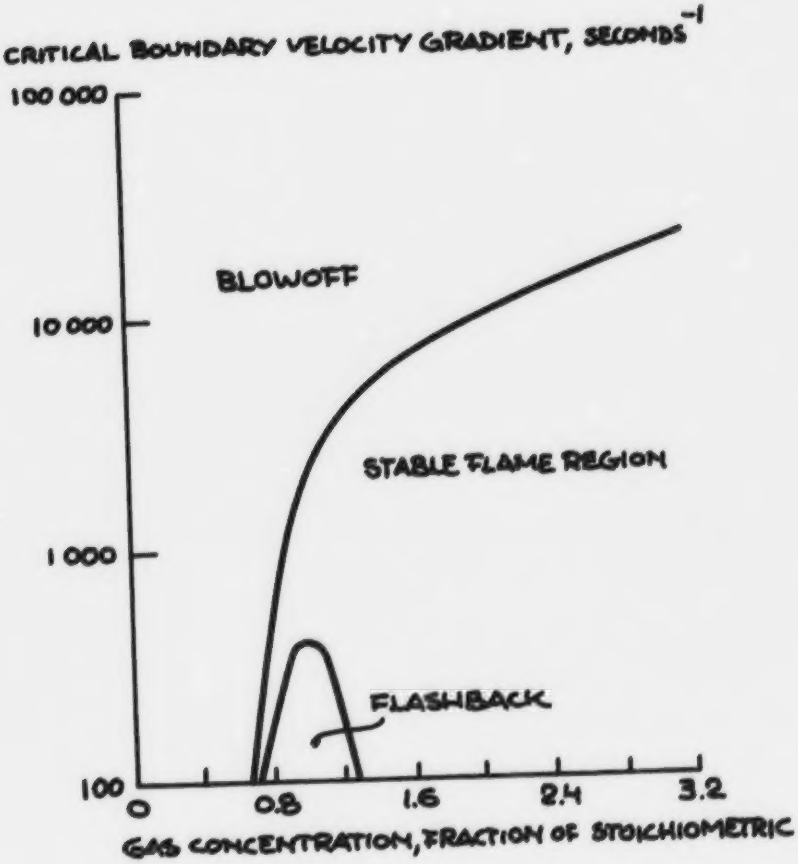


Figure 11-2

Flame-stability diagram for a fuel containing 100 % CH_4 (5).

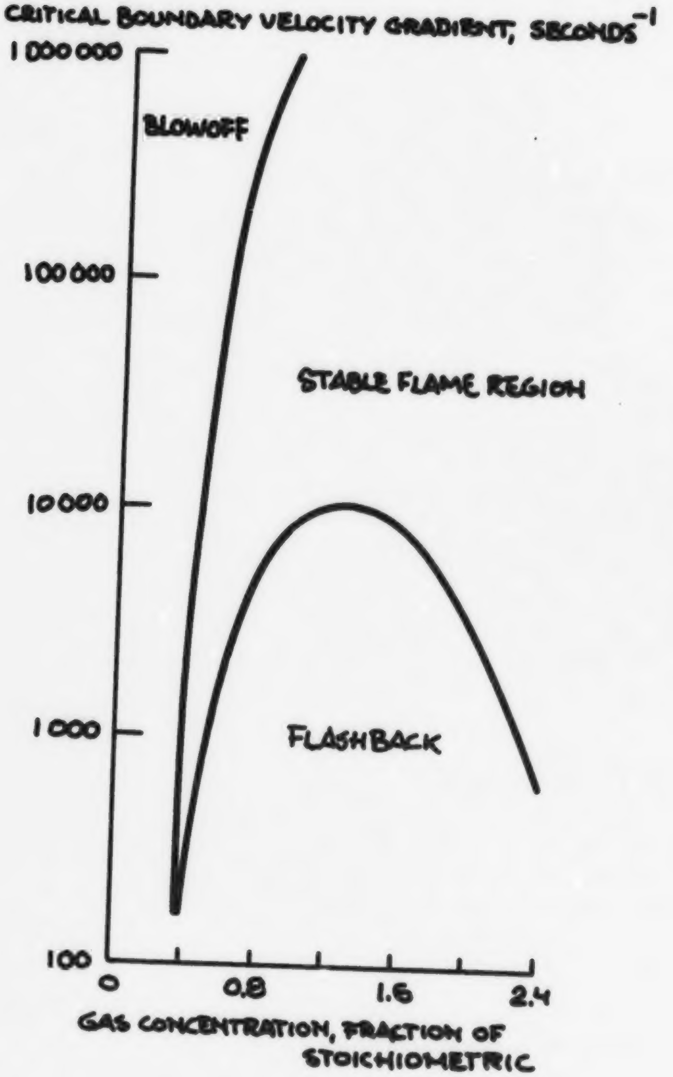


Figure 11-3

Flame-stability diagram for a fuel containing 99.7 % hydrogen and 0.3 % oxygen (5).

11.2.2 Hydrogen used as the driving energy for heat pumps

Hydrogen for heat generation can either be burnt directly or used as the fuel in a heat pump. The advantage of the heat pump alternative is that it offers an opportunity to generate a larger amount of useful heat than was originally supplied by the hydrogen. Almost all heat pumps are electrically driven today, but it seems feasible to believe that hydrogen fuelled heat pumps will be developed if hydrogen is shown to be a suitable fuel.

The ratio between the amount of useful heat and the energy supplied with the fuel is often referred to as the coefficient of performance or COP. For fuel driven heat pumps, the COP can be calculated, (see Figure 11-4):

$$\mathrm{COP} = \eta_m \cdot \eta_{ct} \cdot \frac{T_1}{T_1 - T_2} + (1 - \eta_m) \cdot \eta_r$$

where

η_m = is the mechanical efficiency of the driving engine

η_{ct} = is the efficiency of the heat pump cycle relative to the Carnot efficiency

η_r = is the efficiency of reject heat recovery

T_1, T_2 = are the temperatures of the heat pump condenser and evaporator.

The investment costs of a heat pump are larger than those of a burner. With increasing energy cost relative to the cost of manpower, heat pumps will gradually become more competitive.

11.2.2.1 External combustion engines

Among all possible external combustion processes, the following are considered as the most interesting for heat pump applications:

- Gas turbine (Brayton cycle)
- Steam turbine (Rankine cycle)
- Stirling motor (Stirling cycle)

The gas turbine is today a low investment - low efficiency machine. The low efficiency originates from the relatively low gas temperature. The temperature is kept restricted, mainly due to the materials available for the turbine blading. The efficiency of gas turbines would be significantly enhanced if the gas temperature could be raised. New ceramic materials resistant to such temperatures must then be developed. It is not clear how they would effect the investment cost of the gas turbine.

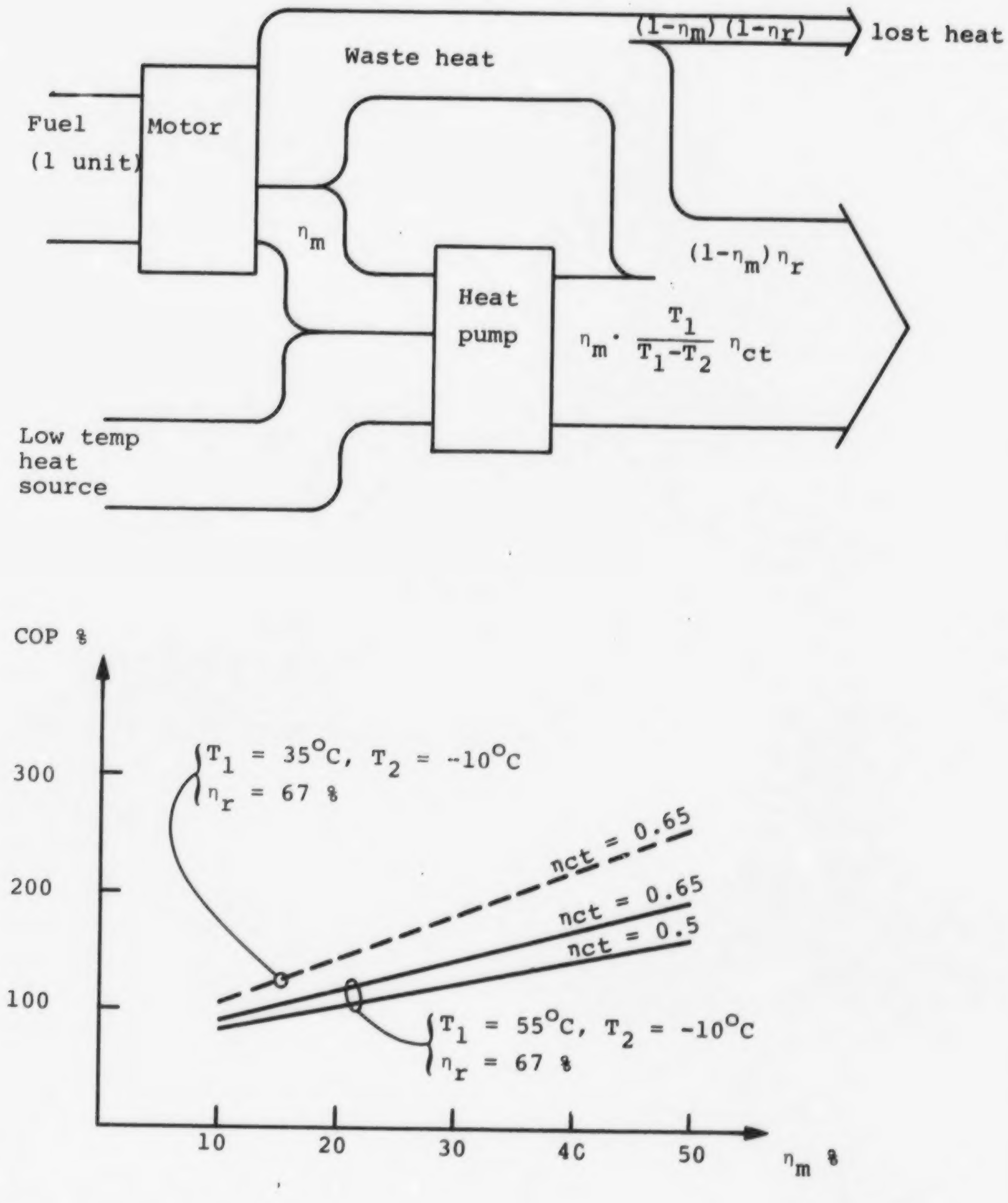

(1-ηm) (1-ηr)
lost heat
Waste heat
Fuel
(1 unit)
Motor
ηm
(1-ηm) ηr
Heat pump
ηm · T1/(T1-T2) ηct
Low temp heat source
COP %
300
200
100
T1 = 35°C, T2 = -10°C
ηr = 67 %
ηct = 0.65
ηct = 0.65
ηct = 0.5
T1 = 55°C, T2 = -10°C
ηr = 67 %
10
20
30
40
50
ηm %

Figure 11-4

Energy flows and COP for a fuel driven heat pump.

The steam turbine has at present a somewhat higher efficiency than a gas turbine. The investment cost is also higher. Both steam turbines and gas turbines require today a fairly high output power to be economically feasible. Intensive research work (10) is being undertaken to develop small Rankine cycle driven heat pumps.

Stirling machines on the contrary have reasonably good efficiencies even in small units. With a high efficiency, the Stirling cycle could operate with hydrogen as the working medium. One of the most difficult tasks when developing Stirling machines has been to develop sealings for a hydrogen system. It can, however, be argued that if hydrogen is available in large quantities, a small leakage could be tolerated without upsetting the economy.

11.2.2.2 Internal combustion engines

Two types dominate the market picture:

- The Otto engine
- The Diesel engine

Otto engines have lower efficiencies than Diesel engines but are cheaper to manufacture. Both types belong to the "small engines" group. The operating efficiency for both is enhanced, if conventional hydrocarbon fuels are replaced by hydrogen.

11.2.2.3 Fuel cells

The fuel cell is probably the most promising energy converter for hydrogen heat pumps. The efficiency today is already very high (around 50 % maximum) but the cost is also large. The high costs are mainly due to expensive electrode materials (6). Maybe cheaper electrode materials will be developed in the future.

11.2.3 Transport of hydrogen inside buildings

The supply of residential and commercial buildings with hydrogen as well as its internal distribution to different energy consuming stations will naturally occur as a gas in a pipeline system.

The practice was earlier to distribute natural or synthetic gas to the consumer at a low pressure, 1 - 3 kPa above atmosperhic pressure, with cast iron as the commonly used piping material.

Very few households in Sweden are today equipped with an internal gas distribution system. If new gas distribution systems are to be introduced aiming primarily at utilizing natural gas, it is essential that all material installed should be compatible with hydrogen.

11.2.4 Small-scale storage of hydrogen

Hydrogen might be stored at each application site and be batchwise distributed just like oil is today. The most reasonable storage systems are hydrides and compressed gas. In the case where hydrides are used, chemical heat pumps could be combined with the storage.

11.3 Safety considerations

Hydrogen is a potentially very dangerous fuel due to the high explosion risk and the low ignition energy (Chapter 14). The flammability limits are 4 - 75 % by volume compared to 5 - 15 % for natural gas. Another dangerous property of hydrogen is that the hydrogen flame is invisible and has a very low radiative heat transfer. This means that it is very easy to get burnt without any previous warning. Great care must therefore be taken to construct a foolproof system in all household applications.

Hydrogen has a leakage tendency by volume which is about 3 times greater than that of methane. While the diffusion rate of methane directly through a wall piping can be considered as negligible, the use of hydrogen can impose a real risk in connection with some plastic materials. The volumetric permeability of such materials for H_2 can be about 100 times greater than that for methane. However, if hydrogen leaks out into a room, the simultaneous rate of leakage from the room is considerably higher than that for natural gas. This limits the concentration of hydrogen which can be achieved.

In order to warn people of hydrogen leaks, it is necessary to add an odourizer. The odourizer used must of course be compatible with all potential applications of the gas, for example all likely types of fuel cells and catalytic burners.

The odourizer gives a fair warning when there are people present who can detect the smell, provided there is no heavy "smell background". However, there are also localities where no people are present for long periods and where an explosion could still be hazardous. In such localities it might be advisable to install some kind of electronic warning equipment. This equipment should either give an alarm or shut off the hydrogen supply automatically.

An illuminant should also be added to the hydrogen in order to allow visual detection of the flame. The illuminant must also be compatible with for example fuel cells. Illuminants suggested are organometallic sodium or aromatic organic materials.

11.4 The market in the heating sector

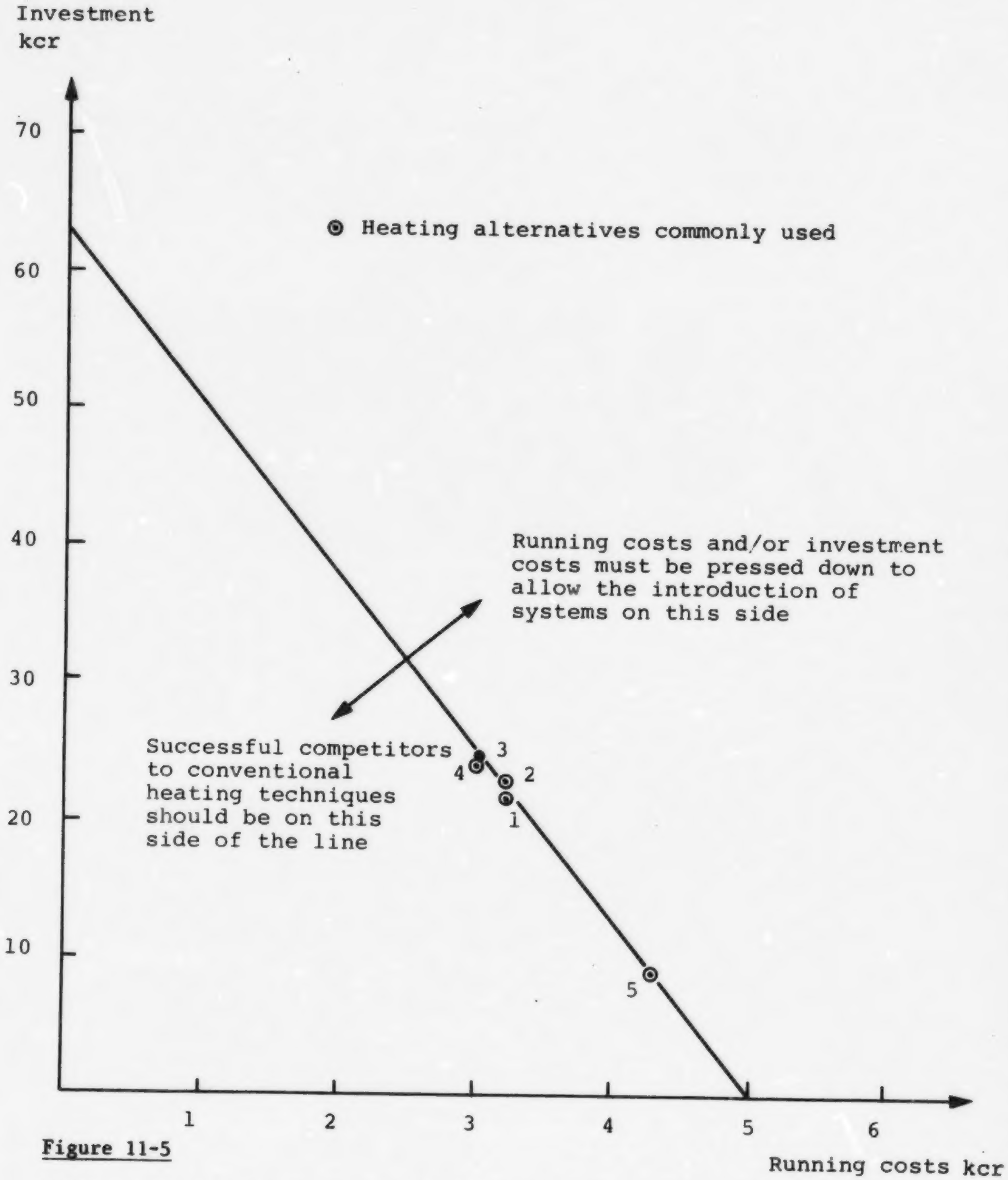
Three different energy scenarios have been worked out and form the basis of this study (Chapter 4):

A	Nuclear power
B	Renewable sources
C	Natural gas and imported fuels

In each scenario, the competitiveness of hydrogen to other energy carriers is to be estimated.

11.4.1 The situation in Sweden today

In Figure 11-5, the cost situation for the heating of private houses today is illustrated. The running costs per year for a number of alternatives can be read on the x-axis, and the total investment for the alternatives can be read on the y-axis.



Running costs and/or investment costs must be pressed down to allow the introduction of systems on this side

Successful competitors to conventional heating techniques should be on this side of the line

Figure 11-5

Relations between investment and running costs for different heating alternatives for singel family houses according to FERA 78-08-02 (7).

1. **Separate oil furnace**
2. **Oil furnace and electric supplement**
3. **Oil furnace**
4. **District heating**
5. **Direct resistance heating**

In Sweden today, the most common heating alternatives for private houses are:

- Direct electric resistance heating
- Oil furnaces (in each house)
- District heating
- Oil furnace with electric supplement (in each house)

If a line is drawn in Figure 11-5 through these four common alternatives, two conclusions can be drawn. The first is that the market today seems to use an annuity of about 8 % as an average. All the alternatives regarded then seem to have about the same "degree of economical attractiveness". The second conclusion is that when using this annuity factor the annual costs for an average private house consumer amount to about 5000 cr/year or about 0.2 cr/kWh (0.06 cr/GJ), including capital costs for the heating equipment. The cost of insulation is not, however, taken into account. For larger consumers, it is difficult to estimate the cost picture in the same way, as this group is more heterogeneous.

Table 11-2

Cost of heating equipment, cost level 1978.

Thermal power	System	Cost (cr)	Ref
< 10 kW	Electric radiators & system	6500	7
	Water radiators & system for furnace	9500	7
	Water radiators & system for heat pump	10000	7
	Electric heater for hot tap water	2500	7
	Supply system for hot water	9000	7
	Oil (or methanol) furnace with tank and chimney	12000	7
	Electric heat pump	17000	7
	Fuel heat pump	25000	*
	Biomass stoker and storage	25000	8
	Biomass furnace with chimney	10000	8*
	Heat exchanger for district heating	10000	*
1 MW	Biomass furnace 950 - 1200 cr/kW	10^6	11
40 MW	Biomass furnace 400 - 600 cr/kW	$20 \cdot 10^6$	11
4 MW	Oil (or hydrogen) furnace	$1.2 \cdot 10^6$	*
	Heat pump system	$4 \cdot 10^6$	*
	External heat distribution network	$4 \cdot 10^6$	*

* Estimated here

11.4.2 Scenario A, nuclear

In this scenario, direct hydrogen burners and hydrogen heat pumps will compete with direct resistance heating and electric heat pumps. Nuclear district heating is applied for larger buildings and industries in more densely populated areas.

11.4.2.1 Private houses

Assumptions about investment costs for different alternatives can be seen from Table 11-2.

Table 11-3 shows the energy costs at consumer level for various types of energy according to this study.

Table 11-3

Energy costs cr/GJ.

Energy carrier	Production		Transport		Storage		Total	
	2005	2025	2005	2025	2005	2025	2005	2025
GH_2	51	62	1.0	1.0	0.8	0.8	52.8	63.8
Petrol	36.5	61.4	2.2	2.2	0.05	0.05	38.8	63.7
NG	23.0	38.3	0.7	0.7	0.3	0.3	24.3	40.3
SNG	23.5	34.0	0.7	0.7	0.3	0.3	24.5	35.0
Electricity	39	54	10.8	10.8	-	-	49.8	64.8
Methanol (biomass)	58	60	4.5	4.5	0.2	0.2	62.5	64.7
Wood	17	18	4.0	4.5	-	-	21.0	22.5
Biomass	12.2	13	3.5	4.0	-	-	16.0	17.0
Peat	11	12	3.5	4.0	-	-	15.0	16.0

Table 11-4 estimates the total costs in 2005 and 2025 for four different heating alternatives for a house consuming about 54 GJ/year. An annuity of 8 % has been used in accordance with Figure 11-5, which with a real interest of 4 % means a depreciation time of c. 17 years.

Table 11-4

Scenario A, investment (cr) and heating costs (cr/year) for a private house. Energy consumption 54 GJ/year.

	Investments	Electricity		Hydrogen	
		Resistance	Heat pump	Burner	Heat pump
	Radiators	6500	10000	9500	10000
	Furnace & hot water	2500		12000	
	Heat pump		17000		25000
	Total (cr)	9000	27000	21500	35000
	Capital cost (8 % annuity)	720	2160	1720	2800
Year 2005	Efficiency or COP (assumed)	1.0	3.0	0.9	2.0
	Cost of energy (cr/year)	2689	896	3168	1425
	Total cost (cr/year)	3409	3056	4888	4225
Year 2025	Efficiency or COP	1.0	3.5	0.9	2.5
	Cost of energy (cr/year)	3499	1000	3828	1378
	Total cost (cr/year)	4129	3160	5548	4178

Table 11-5

Scenario A, investments (Mcr) and heating costs (Mcr/year) for 1000 flats, each with a specific energy consumption of 36 GJ/year and a power demand of 4 kW.

		Electricity		Hydrogen	
	Distribution method	Electric	District heating	District heating network	
	Energy converter	Resistance	Heat pump	Burner	Heat pump
	Investments:				
	Radiatiors and heat exchangers	6.5	9.5	9.5	9.5
	Furnace			1.2	
	Heat pump		4		4
	External heat distribution net		4	4	4
	Total (Mcr)	6.5	17.5	14.7	17.5
	Capital cost Mcr/year 8 % annuity	0.52	1.40	1.18	1.40
Year 2005	Efficiency or COP (assumed)	1	4.0	0.85	3.0
	Cost of energy (Mcr/year)	1.79	0.45	2.24	0.63
	Total cost (Mcr/year)	2.31	1.85	3.42	2.03
Year 2025	Efficiency or COP (assumed)	1	4.5	0.9	3.5
	Cost of energy (Mcr/year)	2.33	0.52	2.55	0.66
	Total cost (Mcr/year)	2.85	1.92	3.73	2.06

In this scenario, hydrogen will probably not be used to heat private houses, as electrical heat pumps give significantly lower costs.

11.4.2.2 Large buildings

According to the scenario description, district heating is introduced to a rather small extent. The "waste heat" from three large nuclear power stations is used to heat the three largest cities in Sweden, and seven nuclear district heating units are introduced to heat some other large population centres. No other district heating centres will be in use during the later part of the study period.

In order to check the competitiveness of hydrogen heating for larger buildings in other densely populated regions, cost comparisons were made with electricity for different distribution modes, Table 11-5.

It can be concluded that hydrogen driven heat pump systems are not competitive with electrically driven heat pumps for these houses. Thus - probably - no market for hydrogen heating exists in scenario A.

11.4.3 Scenario B, renewable resources

According to the scenario description, most large buildings are connected to district heating systems where the primary energy is biomass, peat or solar energy.

The heating alternatives for private houses and their costs are given in Table 11-6. The same data for the heating of 1000 flats are shown in Table 11-7.

The calculations show that biomass in central facilities is the cheapest alternative. In places to which biomass cannot be economically transported, methanol and hydrogen - used in heat pumps - are equally good.

The possible market for hydrogen and methanol versus biomass has been estimated using the SRI Gulf model (12). The constants in the model were estimated by applying the model to the observed shift in Sweden from coal to oil for heating purposes. If hydrogen is introduced for space heating in the year 2000, the model indicates that ~ 5 PJ hydrogen will be used in the year 2005 and ~ 50 PJ will be used in the year 2025. Of course figures like these are very uncertain.

11.4.4 Scenario C, natural gas and imported fuels

In this scenario, hydrogen is mainly competing with synthetic imported fuels. It is further assumed that a national gas distribution network (for NG) was introduced during the last decades of the 20th century and has a construction standard compatible with the distribution of hydrogen gas.

During the last part of the period studied, hydrogen is mainly competing with synthetic gas (SNG) which requires almost the same equipment as hydrogen and thus has the same capital costs. From Table 11-3 it is evident that synthetic gas is much cheaper than hydrogen. Thus from an economic point of view it is clear that SNG will be preferred to hydrogen within the heating sector.

Table 11-6

Scenario B, investment (cr) and heating cost (cr/year) for a private house in 2005. Energy consumption 54 GJ/year.

	Investments	Biomass	Methanol			Hydrogen	
		Individual	District heat	Burner	Heat pump	Burner	Heat pump
	Radiators	9500	9500	9500	10000	9500	10000
	Furnace incl. stoker and storage	35000	5000	12000		12000	
	Heat pump				25000		25000
	Hot water distribution		7000				
	Heat exchanger		10000				
	Total (cr)	44500	31500	21500	35000	21500	35000
	Capital cost (8 % annuity)	3560	2520	1720	2800	1720	2800
Year 2005	Efficiency or COP (assumed)	0.9	0.8	0.9	2.0	0.9	2.0
	Cost of energy (cr/year)	942	1059	3750	1687	3168	1425
	Total cost (cr/year)	4502	3579	5470	4487	4888	4225
Year 2025	Efficiency or COP (assumed)	0.9	0.85	0.9	2.5	0.9	2.5
	Cost of energy (cr/year)	990	1048	3870	1393	3828	1378
	Total cost (cr/year)	4550	3568	5590	4193	5548	4178

Table 11-7

Scenario B, investments (Mcr) and heating costs (Mcr/year) for 1000 flats, each with a specific energy consumption of 36 GJ/year and a power demand of 4 kW.

	Investments	Biomass	Methanol		Hydrogen	
		Distr. heat	Burner	Heat pump	Burner	Heat pump
	Radiators	9.5	9.5	9.5	9.5	9.5
	Furnace	3.0	1.2		1.2	
	Heat pump			4.0		4.0
	External heat distr. network	4.0	4.0	4.0	4.0	4.0
	Total (Mcr)	16.5	14.7	17.5	14.7	17.5
	Capital cost (8 % annuity)	1.32	1.18	1.40	1.18	1.40
Year 2005	Efficiency or COP (assumed)	0.8	0.8	3.0	0.85	3.0
	Cost of energy (Mcr/year)	0.707	2.81	0.75	2.24	0.63
	Total cost (Mcr/year)	2.03	3.99	2.15	3.42	2.03
Year 2025	Efficiency or COP (assumed)	0.85	0.85	3.5	0.9	3.5
	Cost of energy (Mcr/year)	0.70	2.73	0.66	2.55	0.66
	Total cost (Mcr/year)	2.02	3.91	2.06	3.73	2.06

If hydrogen were produced by coal gasification, the energy costs difference as compared to SNG would become smaller, and hydrogen would become a possible alternative. Another factor working in favour of hydrogen is the environmental aspect. Apart from electricity, hydrogen is the cleanest fuel known, and it is quite feasible that the authorities will encourage the use of hydrogen on these grounds. It is not, however, possible to foresee the influence of such governmental support.

11.5 Summary and conclusions

In scenario A, no hydrogen will be used to heat buildings in Sweden during the studied period. The total cost of the cheapest hydrogen heating method is too high to compete with electric heat pumps. Furthermore, electric heat pumps are expected to be a very well established technology by the year 2000, thus giving other heat pump systems only a small chance.

In scenario B, hydrogen heating could be an interesting alternative due to the higher costs of other heating methods. The market has been estimated to be 5 PJ in the year 2005 and 50 PJ in the year 2025.

In scenario C, no use of hydrogen is anticipated due to unfavourable competition from SNG. Governmental environmental regulations could, however, change this situation.

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12. TRANSPORTS

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12.1 Identification of interdependent factors in a transition to a hydrogen fuelled transportation system

The limitations of present-day technologies, characterized by tactical decisions to keep things going, will often result in statements like "that could never happen" when radical departures from established technology are being considered. This is especially true when discussing a hydrogen-oriented transportation system; actually it has been said that if hydrogen fuelled cars are proved to be feasible then all other aspects of a hydrogen economy can be achieved.

However, a hydrogen-based transportation system does not only require a different technology for the vehicles, but it must also be supported by an extensive network of fuel production, transmission, storage and distribution. Further, infrastructures of component production, vehicle maintenance and repair, knowledgeable personnel and equipment are required.

In spite of this background, the situation for hydrogen-based transportation is not unique. There are several examples in societies where infrastructure networks have gradually developed (sometimes without competition). Once established, they tend to be very rigid and stubbornly resist any imposed changes, thereby becoming prominent characteristics of a system. Examples can be found in electrical power distribution, television systems, railroad transportation etc.

Hydrogen fuelled heat engines and fuel cells have been studied in laboratories and have also been installed in suitably converted automobiles. Thus, from a technical point of view, hydrogen fuelled vehicles already exist. However, the private individual regards his vehicle as means to personal mobility. Any change in the automotive network which disrupts the accustomed feel of mobility will therefore be resisted by the consumer. It is a common experience that widely spaced fuel stations or a lower availability of a particular fuel in certain geographical regions is experienced as a loss of convenience by the affected car owners. A hydrogen distribution and retailing system is quite different from a hydrocarbon logistics network. Any move towards hydrogen fuelled transportation would therefore be felt as unnecessarily disruptive.

Looking back at the history of transportation, there are several instances where entirely new and more complex systems have evolved from simpler ones. For instance, the established horse and stable system was probably regarded as a better choice in comparison with the automobile and service station of that day. The gradual conversion to petrol fuelled vehicles was the result of economic and social forces operating in the market place.

In the general transportation field, hydrogen logistics could possibly develop first around airfields for hydrogen fuelled experimental aircraft, and then extend to service vehicles using the airfields. Experience from the operation of these might be an evolutionary step towards a wider use of hydrogen fuelled vehicles.

The consumer's attitude is only one of the institutional factors which are closely tied to the fuel network. Oil companies constitute another party with strong economic incentives for preserving the existing network. As long as these companies can supply petrol in quantities requested by the consumers, they have little interest in a transition to hydrogen. If the importation of natural crude oil should become uncertain, the oil companies would probably turn their attention to synthetic fuels which could be manufactured from imported coal or from domestic primary energy sources. By this means, the existing facilities for distribution, refining and marketing, which are based on crude oil as a primary source, might be protected from a too early obsolensence. Thus a slow transformation from dependence on conventional oil sources to synthetic fuels is probably more attractive than the development of a hydrogen system.

Automobile manufacturers would also be concerned about consumers' attitudes towards hydrogen fuelled vehicles and the attitudes of oil companies towards a hydrogen fuel network.

Obviously, the interest of three interdependent parties, oil companies, car manufacturers and consumers, must be coordinated in a successful transition to a hydrogen fuelled transportation system. This necessary coordination is of course a limitation in a free market system. However, similar transitions have been achieved earlier in the history of transportation.

The international character of the automobile industry must also be borne in mind. A substantial part of the development work carried out by automobile manufacturers is devoted simply to adjustments of engine emission characteristics so as to conform with the regulations in different countries. Consequently, support from the government is probably essential to a transition towards a hydrogen economy. The character of the support could vary. It could consist of internationally coordinated legislation, in the field of emission, specific fuel consumption and fuel interchangability. It could also take the form of pressure on consumer attitudes, for instace by means of taxation. A limited market could also be created. Naturally, R & D funds could also be provided.

The time factor is another important item to be considered. The useful life of typical items in the field of transportation is roughly about ten years. Therefore, when a board of directors is planning ahead they must work on a long-term basis. A decision to promote hydrogen fuelled transportation would be facilitated if an energy policy can be formulated which appears to be far-sighted, well-defined and internationally coordinated. Unfortunately, the political time constant is about four years (the time between reelections). Thus, the risk of suboptimizations is obvious, as there is pressure on governments to produce results during their mandatory periods.

Different basic energy sources, such as coal, nuclear, NG and renewable sources, may be used with established, straightforward technologies to provide heat or mechanical power (electricity) according to the needs of society. Battery-powered electric vehicles will obviously adapt the transportation system to any basic energy profile, provided that the battery capacity is sufficently enlarged. If this is not achieved, then a fuel that can be carried on board the vehicles must be found for the transportation system, and this fuel may be very different from the basic energy source in a given energy supply scenario. Naturally, it would be advantageous if intermediate energy carriers could be found which are suitable for use in the transportation system regardless of the choice of primary energy supply. Strong candidates for such intermediate energy carriers are probably methanol and hydrogen, as they are relatively independent of the basic energy carrier profile, Figure 12-1.

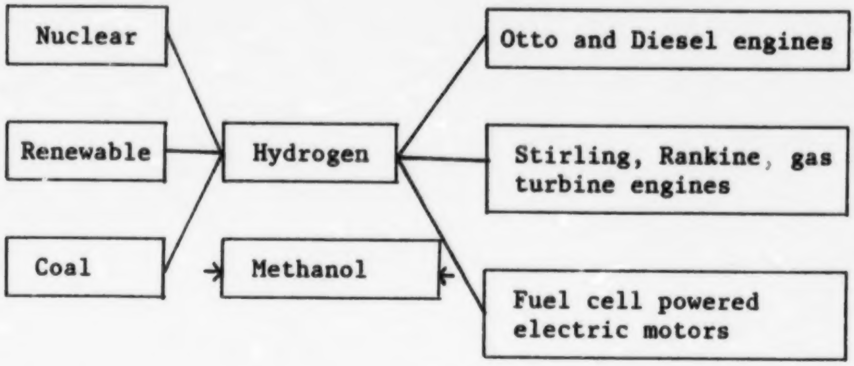

Nuclear
Renewable
Coal
Hydrogen
Methanol
Otto and Diesel engines
Stirling, Rankine, gas turbine engines
Fuel cell powered electric motors

Figure 12-1

Hydrogen and/or methanol as "common denominators" in different energy supply scenarios for transportation.

12.2 Alternative fuels for transport

12.2.1 The prospects for hydrogen in transportation

As discussed earlier, important stakeholders in the transportation system are car manufacturers, oil companies and customers. The latter will favour those alternatives which give an optimum of personal mobility in relation to costs and inconvenience. Thus, changes in energy technology which cause the least deviations from normal operations will be the easiest to introduce. For instance, the introduction of a new engine could be achieved stepwise simply as new cars are sold. On the other hand, the introduction of a different fuel may require modifications in the entire fuel network. Therefore, strong incitements must exist for the introduction of fuels like hydrogen which deviate largely from traditional fuels.

Part of the interest in a hydrogen economy may have emanated from attempts to solve combustion-generated air pollution problems. In particular when confronted with polluted urban air, mainly generated by automotive vehicles, the need for different or modifed propulsion systems is strongly felt.

Hydrogen possesses som valuable fundamental characteristics. It can be manufactured from water using any primary energy source. As water is an inexhaustible resource, a transition to hydrogen could be made permanent. When it is used in a combustion unit, water is the main combustion product. However, hydrogen is not a primary energy source and it is not found in its elemental state in nature.

The close relationship between hydrogen and electricity could offer many development possibilities in transportation. Hydrogen can be used to generate electricity either by means of a combustion process or in a fuel cell for propulsion purposes. In several primary energy supply scenarios, both hydrogen and electricity could serve as common denominators, since they are interchangeable energy carriers. The common denominator aspect will be of value for the end user. He does not have to bother about the nature of the primary energy source as long as his demands for electricity or hydrogen are met.

Although hydrogen possesses several fundamentally attractive features, it also has inherent characteristics that are very different from those of the energy forms which are traditinally used in various societies. Thus, the consequences of a hydrogen technology are not self-evident, and these must be evaluated together with competing alternatives.

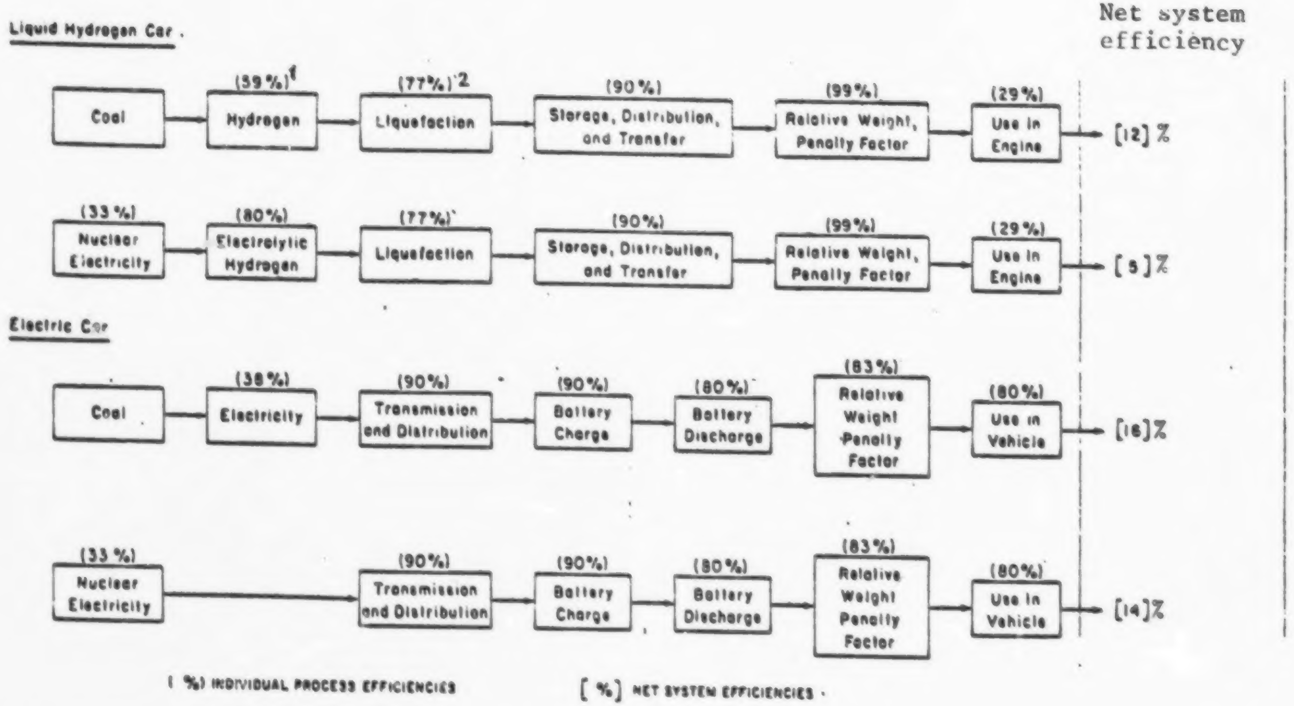
When certain goals in society are specified, it is often necessary to illustrate the consequences of various pathways, possibly in economical terms. Beginning on a microscale, it is quite possible to relate a single technical parameter (for instance a decrease in the fuel consumption of an automobile) to economical terms. However the economic evaluation of interfering technical parameters (such as fuel economy, emission and multi-fuel features) will present difficulties because the relative weight of each parameter is not self-evident. The relative importance is not a technical but rather a political issue.

On a marcroscale, corresponding parameters such as resource utilization and total pollution may be specified. Energy conservation aspects may require an optimum resource utilization. The total energy efficiency accompanying the use of synthetic fuels is dependent on the efficiency of the different processes for manufacture, distribution, storage and consumption in automobiles. As an example, a comparison of the total energy efficiency of various automotive synthetic fuel is shown in Figure 12-2. Similar aspects may also be applied to the total pollution.

Although technological transitions may be expressed in economic terms, there is no obvious way of quantifying the accompanying social values, such as air quality, safety and non-dependence on oil imports.

12.2.2 Competing alternative energy carriers

Large investments have already been made within the established energy fields. The infrastructures are resistant to significant evolution, so that changes are limited to small increments, and energy carrier development has to adjust to the existing structure. For instance, the production of synthetic petrol from coal is economically motivated because it suits the existing storage, distribution and end-user structure. Syntetic fuels, whose molecular structures resemble those of conventional fuels, may therefore conveniently be gradually introduced into existing networks.


Liquid Hydrogen Car.
Net system efficiency
Coal
(59%)1
Hydrogen
(77%)2
Liquefaction
(90%)
Storage, Distribution, and Transfer
(99%)
Relative Weight, Penalty Factor
(29%)
Use in Engine
[12]%
(33%)
Nuclear Electricity
(80%)
Electrolytic Hydrogen
(77%)
Liquefaction
(90%)
Storage, Distribution, and Transfer
(99%)
Relative Weight, Penalty Factor
(29%)
Use in Engine
[5]%
Electric Car
Coal
(38%)
Electricity
(90%)
Transmission and Distribution
(90%)
Battery Charge
(80%)
Battery Discharge
(83%)
Relative Weight Penalty Factor
(80%)
Use in Vehicle
[16]%
(33%)
Nuclear Electricity
(90%)
Transmission and Distribution
(90%)
Battery Charge
(80%)
Battery Discharge
(83%)
Relative Weight Penalty Factor
(80%)
Use in Vehicle
[14]%
(%) INDIVIDUAL PROCESS EFFICIENCIES
[%] NET SYSTEM EFFICIENCIES

Notes:

1. Includes energy utilization for coal to product, coal for process heat, and coal for steam and electricity.
2. SRI internal data.

Figure 12-2

Energy resource utilization for hydrogen-fuelled and electric cars (1).

The same reasoning applies to gas, where substitute natural gas (SNG) manufactured from coal is a strong competitor to hydrogen. The gas industry can gradually increase production and introduce SNG into existing networks when natural gas sources are becoming scarce.

Some experience already exists concerning the difficulties of introducing a slightly different fuel, i.e. non-leaded petrol, in fuel networks. Studies are being performed on the introduction of methanol-blended petrol or pure methanol, which are also competitors to hydrogen. These studies will give further indications of the rigidity of the present fuel distribution system and end-user equipment (vehicles). Introduction of a fuel like hydrogen, which requires extensive changes in both the vehicle and the distribution network, will be more difficult.

The prospects of relying on an existing, alternative energy carrier network are appealing. Therefore, hydrogen must also face competition with electricity. Institutionally, also electric power has many similarities with synthetic oil and SNG systems. Moreover, the introduction of new primary energy resources would only concern the production of electricity and not affect the distribution network and the end-user. In any energy supply scenario, therefore, the electric vehicle has opportunities for market penetration, provided the limited range and performance are accepted. Of course, the electric car will not preserve the existing fuel network, but the manufacturer and consumer will in principle be independent of the present fuel distribution system since batteries may be recharged wherever electricity is present. Moreover, in less developed areas, electricity may be generated locally by means of a suitable Carnot cycle using wood, alcohol etc as fuel. Furthermore, the electric car has no combustion-generated exhaust fumes. As with the hydrogen car, most emissions are concentrated at a central power or fuel manufacturing factory.

An electric propulsion unit could also make use of hybrid propulsion characteristics by using both fuel cells and rechargeable batteries. The fuel cells could be powered by hydrogen or hydrogen generated on board.

Private cars are the largest energy consumers within the transportation system. From the discussion above, it is obvious that a turnover to a synthetic fuel like hydrogen will impose a drastic change on society and individuals.

As regards fleet vehicles, prospects for hydrogen fuel are brighter. Fleet operations will not affect convenience as private cars do. However, within fleet systems alternative energy carriers (mainly electricity) and propulsion units have already been introduced on a small scale. In fleet operations over short distances, electricity is a strong competitor to hydrogen, whereas in operations over long distances with fixed end-points, hydrogen could be more competitive.

There are some promising prospects for hydrogen fuel in the aeronautical field. Simplified but fundamental calculations show that the aeroplane range is directly proportional to the energy content (J/kg) of the fuel. As hydrogen possesses an energy content about three times that of kerosene, an increase in aeroplane performance is possible. Methanol, another hydrogen competitor, has only half the energy content of kerosene. The small-scale use of cryogenic hydrogen in certain applications is already technically well known; liquid hydrogen is often used as a rocket fuel. In the case of LTA vehicles (air ships), nuclear power could offer an almost "infinite" range, as is also the case for nuclear powered surface ships. But gaseous hydrogen fuel, because of its buoyancy, offers some special advantages in the LTA field.

Trains may be operated with almost any fuel. Gas turbine propulsion, in particular, can effectively use both gaseous and liquid fuels. The liquid fuels may be preferred because of handling simplicity. Electricity is a strong competitor owing to existing distribution networks.

Ships can be operated on almost any chemical fuel except direct electricity. Since they are not limited by weight and volume as are automobiles, the extra volume needed for on-board hydrogen will not be a difficult problem. Nuclear power, which has been used mainly on certain military vessels, also offers a special advantage since the periods between "refuelling" are vastly extended.

12.3 Technical aspects of hydrogen fuelled vehicles

The technical problems in connection with hydrogen fuel for transportation can be solved. This has been verified experimentally since several hydrogen fuelled automobiles have been operated successfully. Actually, the basic chemical and physical processes in heat engines and fuel cells perform advantageously with hydrogen. This is demonstrated by their higher efficiencies and lower emissions. The main barriers to a general adoption, apart from economic, social and political issues, are safety questions and technical problems connected with the storage of hydrogen on board the vehicles.

12.3.1 Hydrogen safety

The special physical and chemical characteristics of hydrogen have implications, not only in safety issues but also regarding performance parameters in propulsion systems. The safety aspects vary more with actual conditions for hydrogen than is normally the case with traditional fuels. For instance, the "autoignition" temperature for hydrogen/air mixtures is stated to be about 580°C. However, it is well known that certain noble metals and metal oxides may ignite hydrogen/air mixtures even at room temperature.

Public perception of hydrogen safety is widely diversified. In general, those who have less access to technical knowledge are more opposed to hydrogen, particularly as they are mainly informed about the hazardeous aspects. Thus, education and information is important, especially as decision makers must act according to public attitudes created by information. In the final acceptance or rejection of hydrogen vehicles, it would not matter whether a certain public attitude were based on a real or imagined perception of hazards.

Some properties of hydrogen in connection with its use in engines and safety precautions are listed in Table 12-1. For comparison, other typical fuels are also incorporated. The table indicates that the flammability range for hydrogen is much wider than for petrol, but that petrol has a lower flammability limit. As hydrogen is more volatile, flammable concentrations are more rapidly reached but also more rapidly dissipated because of the high buoyancy and diffusivity of hydrogen.

Table 12-1

Properties of hydrogen and other fuels relevant to safety in propulsion (1).

Property	Hydrogen (H_2)	Methane (CH_4)	Methanol CH_3OH)	Petrol	Jet fuel (JP-4)
Temperature of liquid at normal boiling point	20.3 K	112 K	338 K	*	*
Heat of vaporization	0.45 MJ/kg	0.51 MJ/kg	1.1 MJ/kg	c. 0.38 MJ/kg	-
Density of hydrogen gas (at normal boiling point) relative to the density of air (at STP)	1.03	1.38	-	-	-
Density of gas relative to the density of air at (STP)	0.070	0.55	-	-	-
Diffusion coefficient	0.63 cm^2/sec	0.2 cm^2/sec	-	0.08 cm^2/sec	-
Flammability limits in air (by volume)	(4.1-74)%	(5.3-15)%	(6.0-37)%	(1.5-7.6)%	(0.8-5.6)%
Ignition energy	20 μJ	300 μJ	-	250 μJ	-
Flame velocity	2.75 m/sec	0.37 m/sec	0.41 m/sec	< 0.3 m/sec	-
Heat of combustion (LHV)	120 MJ/kg	50 MJ/kg	20 MJ/kg	44 MJ/kg	43 MJ/kg
	8.5 GJ/m^3	21 GJ/m^3	16 GJ/m^3	31 GJ/m^3	34 GJ/m^3

* Not applicable; these fuels are not single molecular species, and their components exhibit a wide range of boiling points.

The wide flammability range means that even small leaks from a hydrogen fuel system into an enclosed area constitute a safety problem. For instance, a hydrogen leakage rate of about 0.01 kg/h in a medium-sized private garage would make the air-hydrogen mixture flammable within 24 hours. The lower detonability limit is reached if the leakage rate is about 0.05 kg/h. On the other hand, buoyancy and diffusivity effects tend to counteract the accumulation of combustible mixtures.

When hydrogen burns, the flame is nearly invisible. Therefore fires are difficult to locate; on the other hand, firefighters can get close to the flame because radiation is minimal. The spread of a fire is retarded since the absence of radiation means that surrounding objects are not heated up and ignited unless the flame comes into direct contact. Smoke, which may pose a serious health hazard when inhaled from hydrocarbon fires, is non-existent in hydrogen fires.

There are some safety aspects of hydrogen storage, especially in the liquid form, that should be investigated closely. Several reports from industry describe situations when superheated liquids have exploded. This process is not to be confused with a more or less rapid boil-off; these explosions will occur within microseconds. Thus shock waves are created, and a secondary fuel-air explosion can also be initiated (2).

A typical hazardous situation can involve a fuel tank with a pressurized liquid fuel such as propane or a Dewar tank with liquid hydrogen. If such tanks are heated, for instance by an accidental fire, safety valves will usually be activated. At sufficiently high boil-off rates, the valves may be choked, the rank may rupture and the liquid is rapidly depressurized. The superheated liquid-vapour explosion theory predicts that an explosion may occur if the temperature of the liquid at the moment of depressurization is at a certain level, which depends on the thermodynamic characteristics of the liquid.

In addition, a tank rupture due to mechanical causes may also be hazardous in this respect. Liquid natural gas and other light hydrocarbons have been observed to explode when poured onto water under certain conditions (3). This may prove a big problem for projected sea transports. It has been suggested (3) that superheated liquids can behave as elementary explosives. For instance, liquid methane superheated 50° above its boiling point has a potential energy of explosion which is about 2 - 3 % of that of TNT.

12.3.2 On board storage of hydrogen

A hydrogen fuelled transportation sector requires the development of suitable hydrogen storage systems on board the vehicles. The problem of hydrogen storage is fundamental and independent of the propulsion system (IC or EC* engines or fuel cells) and the transport mode (automobile, ship or aeroplane).

The physical and chemical properties of hydrogen will give rise to storage difficulties in automobiles. The absence of a compact, lightweight and inexpensive method of storing hydrogen is a contributing factor to the limited number of practical demonstrations of hydrogen automobiles to date.

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* Internal Combustion, External Combustion.

In general, hydrogen may be stored as a compressed gas in pressure vessels, as a cryogenic liquid in dewars, or as a solid substance in the form of lightweight hydrides. Compressed gas storage can be modified by the use of hydrogen-adsorbing substances, such as charcoal.

12.3.2.1 Pressure vessel

The storage of compressed gases constitutes a well-known technology. The components and systems are manufactured and used according to established regulations. Consequently, many experimental hydrogen fuelled automobiles have used compressed gas systems.

A typical, standardized pressure vessel has a weight of about 70 kg, a volume of about 60 dm^3 and a fill-pressure of about 18 MPa. The hydrogen stored in such a vessel amounts to approximately 1 kg (142.5 MJ). Thus, the weight ratio of fuel to storage unit is only about 0.015. This is of course very unfavourable, since energy dissipation processes, such as the rolling friction work, increase with vehicle mass. A large fraction of the available energy is required simply to move the heavy hydrogen containers.

The use of pressurized vessels is quite common in rocket and space technology. As low weight is of great importance in these fields, special high pressure vessels have been developed. These have generally a spherical design. The materials used are titanium-aluminium alloys, often in combination with carbon or boron fibres. It is possible to achieve a mass ratio of hydrogen to storage unit of about 0.05. For instance, data for a typical titanium alloy vessel are: diameter 0.66 meters, weight 60 kg, pressure 30 MPa and stored hydrogen mass 3 kg.

Although new materials and new technologies may lead to some developments for high-pressure storage, there are other drawbacks with these systems. If a traffic accident causes a pressure vessel to burst, very high reaction forces are created because of the outflowing gas. Moreover, the hydrogen may be ignited owing to electrostatic phenomena.

In an overall energy balance, the compression energy requirements for high-pressure hydrogen storage must be considered. If a compressor is driven by a hydrogen-fuelled engine, about 20 - 40 % of the energy stored in the hydrogen is used for compression purposes. In principle, part of this energy could be recovered by using som kind of turbine unit when releasing the hydrogen from its high pressure vessel.

12.3.2.2 Sorption systems

By analogy with the method used for acetylene containment, it would be advantageous to use hydrogen-adsorbing compounds and thus to increase the amount of hydrogen stored in a container. However, owing to its extremely low boiling point, hydrogen is only sparsely adsorbed at room temperatures. For instance, activated charcoal adsorb about 1 % of hydrogen at 2 MPa and about 2 % at 10 MPa on a mass basis. Such systems will be very voluminous and therefore less suitable. However, when the temperature is lowered, the adsorption potential is enhanced. For instance, at the temperature of liquid nitrogen, activated carbon adsorbs about 3.6 % of hydrogen at 0.1 MPa and about 5 % at 4 MPa. Such a storage system would correspond approximately to a 75 MPa high pressure storage system, as regards both volume and weight.

Future developments in surface physics may yield compounds with higher adsorption capacities. In general, low temperature storage in pressure vessels, with or without adsorbent compounds, can be regarded as a useful alternative. However, as with cryogenic hydrogen, the energy requirements for creating and maintaining low temperatures must be coped with.

12.3.2.3 Liquid hydrogen storage systems

Recent space projects, for instance Saturn rockets, have used liquid hydrogen as a high-energy fuel. A minimal structure weight is an important requirement within space activities. Thus the design and materials for cryogenic hydrogen storage are fairly well-known.

In general, cryogenic liquids are stored in dewars, that is double-walled vessels with a vacuum between the two walls. The degree of vacuum initially established is improved during use, as any residual gases trapped at room temperature will freeze out. Further improvement of the thermal insulation is obtained by filling the vacuum space with closed-cell plastic foam or multilayer sheets ("superinsulation"). At high vacuum conditions ($\lesssim 1$ Pa), the superinsulation performs better. On the other hand, the insulation characteristics are lost in case of a vacuum breakdown.

A large proportion of the heat loss occurs through thermal bridges, such as structure supports, seams and holes. Consequently, it is necessary to pay careful attention to the design and choice of materials for these construction elements.

Within aerospace programs, aluminium alloys have been the preferred container materials. Certain low-temperature chromium-nickel steels and titanium alloys are also feasible. Taking into account the weight, economics and resource aspects, the aluminium alloys appear to be generally advantageous.

The geometrical configuration of the containers has important implications, for instance as regards installation, structural support and tubing connections. The following geometries for automotive use have been considered.

a) The spherical tank: Theoretically, this has the ideal geometry. However, installation in vehicles of conventional design will pose some difficulties regarding the efficient use of available space.

b) The torus tank: This is unfavourable as regards the surface-volume ratio. Also, manufacture is difficult. However, the empty central space may be used for storing goods.

c) The cylindrical tank: When all factors are considered, this is probably the best choice for vehicular use, at any rate if the pressure is kept below 1 MPa.

d) The elliptical tank: This follows closely the performance of a cylindrical tank.

A particular hydrogen tank design for automotive use must be adapted to requirements such as range, periods of non-operation and installation. A petrol tank with a volume of 33 litres corresponds to an LH_2 tank (at 0.1 MPa) of 124 litres. If overpressures are used, the variable density of LH_2, which is shown in Table 12-2, must be considered.

Table 12-2

Density data for LH_2 (4).

MPa	°C	kg/l
0.1	-252.9	0.0712
0.15	-251.5	0.0694
0.2	-250.4	0.0679
0.25	-249.4	0.0665
0.3	-248.6	0.0653
0.4	-247.2	0.0630
0.5	-246.0	0.0610
0.6	-245.1	0.0590
0.7	-244.2	0.0570
0.9	-242.6	0.0528
1.0	-241.9	0.0504
1.1	-240.9	0.0441
1.2	-240.3	0.0382
1.32	-240	0.0299

Obviously, the fill ratio decreases with increasing pressure. Usually, tanks are maintained at a pressure slightly above ambient in order to prevent outside air from entering the tank and forming an explosive mixture. The system could also become clogged by the frozen air.

A practically verified LH_2 tank system for automotive use, taken from (5), is shown in Figure 12-3. Hydrogen flows from the tank as a liquid and is vapourized in a heat exchanger driven by the water cooling system of the engine. Hydrogen gas, at about atmospheric pressure, then goes to the engine. A relief valve in the line prevents excessive pressure build-up. A pressure of about 0.04 MPa above atmospheric is sufficient to obtain the desired flow rate. If the pressure in the tank should drop below this value, a heating element within the tank is automatically activated.

Heat leakage from the atmosphere will increase the tank pressure during periods of engine shut-off. The tank is therefore vented through a check valve set at 0.25 MPa. The vented hydrogen passes through a catalytic converter and is discharged to the atmosphere as water vapour.

The problems of "boil-off" and "lock-up time" are of concern in LH_2 systems. The former expresses the rate at which hydrogen may be lost from the tank, usually as the percentage of tank capacity lost in 24 hours. Lock-up time refers to the time required for the pressure in the tank to build up from atmospheric (or filling pressure) to the relief pressure at which boil-off begins. Thus the latter is dependent on the relief pressure. The boil-off should of course be as low as possible whilst the lock-up time should be as large as possible. The system in Figure 12-3 may be modified so as to feed vapour directly from the tank to the engine, in which case the tank pressure has to be kept low. At a sufficiently low pressure, the liquid

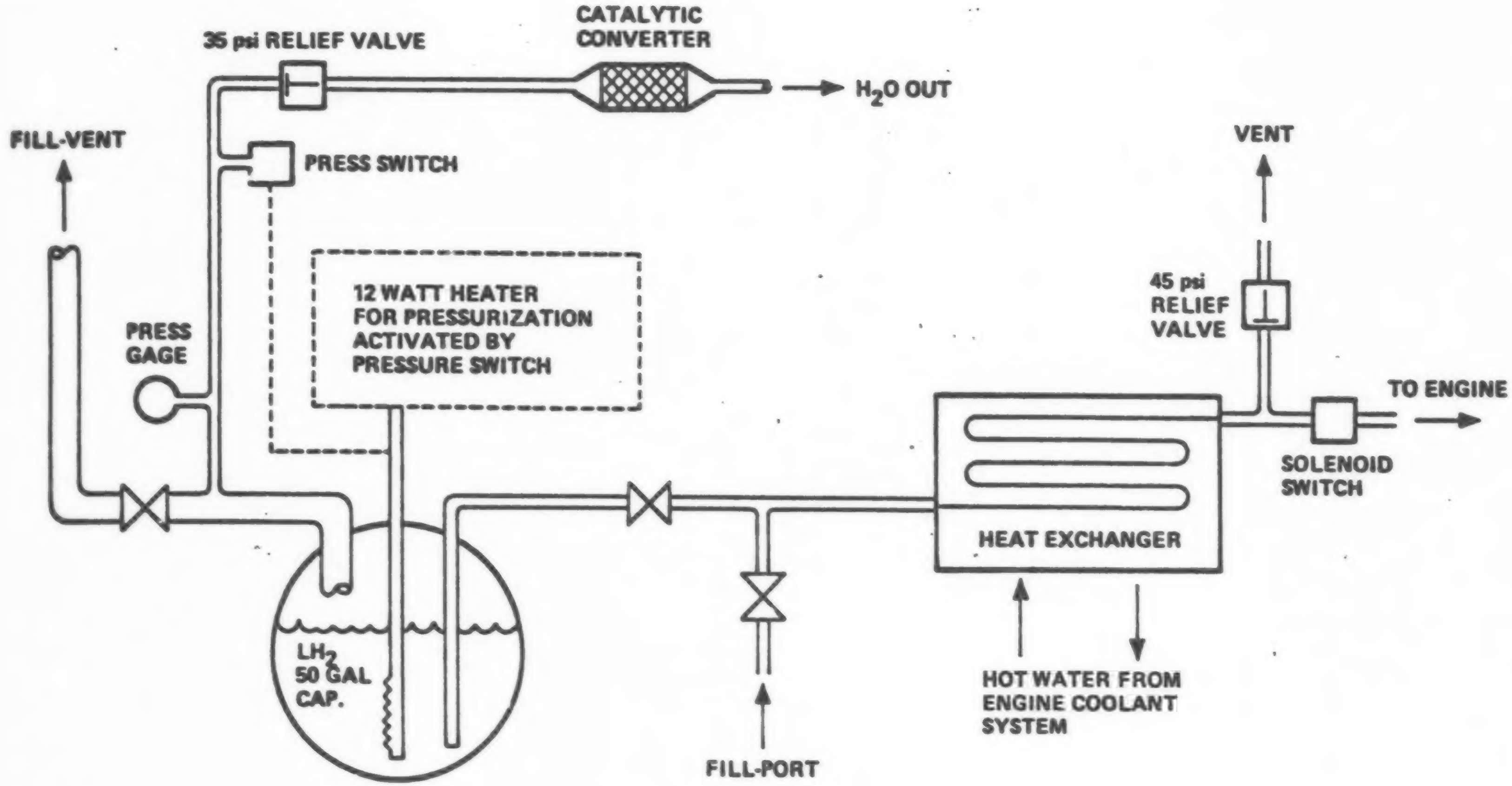

35 psi RELIEF VALVE
CATALYTIC CONVERTER
H_2O OUT
FILL-VENT
PRESS SWITCH
VENT
12 WATT HEATER FOR PRESSURIZATION ACTIVATED BY PRESSURE SWITCH
PRESS GAGE
45 psi RELIEF VALVE
TO ENGINE
SOLENOID SWITCH
HEAT EXCHANGER
LH_2 50 GAL CAP.
HOT WATER FROM ENGINE COOLANT SYSTEM
FILL-PORT

Figure 12-3

A liquid hydrogen fuel system (5). Boil-off ~ 1 %, lock-up period 4 days.

feed system becomes operative. Thus during engine use there will be no boil-off and also, after engine shut off, boil-off will not start until the lock-up period has expired.

Although cryogenic LH_2 fuel systems have been successfully used during long test periods for actual car fuelling, it remains to be demonstrated that widespread handling at the consumer level is foolproof, especially in connection with refill operations, where tubes are frequently disconnected and reconnected. A most important point is the avoidance of flammable hydrogen-air mixtures; this may be accomplished by purging the tubes or spaces involved with an inert gas. Although nitrogen is desirable from an economic point of view for this purpose, troubles may arise with nitrogen condensation. Helium is another alternative but is rather expensive and will impair the economics of an LH_2 fuel system.

12.3.2.4 Metal-hydride storage systems

Hydrogen storage in a metal hydride does not have the same extended historical background as those of compressed gas or liquid storage. Some general advantages with hydride systems may be identified. Compared to LH_2 storage, the energy required for liquefaction is saved, and the design and handling problems with cryogenic liquids are avoided. Compared to storage in pressure vessels, high pressure hazards and unfavourable weight ratios are reduced. Some drawbacks to be mentiond are the energy density, which is lower than for LH_2, inactivation of the hydride bed by small amounts of foreign gases, disintegration of the hydride bed owing to repeated charge-discharge cycles, and possibly autoignited metal fire in case of accidental container ruptures.

Most elements in the periodic table form simple and stable hydrides, Table 12·3 (12). Binary, ternary and higher metal alloy hydrides are also known, but their properties have not been studied extensively until recently. Some of these "higher" hydrides have been shown to be particularly suitable as a hydrogen storage medium, with rapid kinetics for formation and disintegration, suitable temperature and pressure intervals, and resistance to chemical and mechanical destruction.

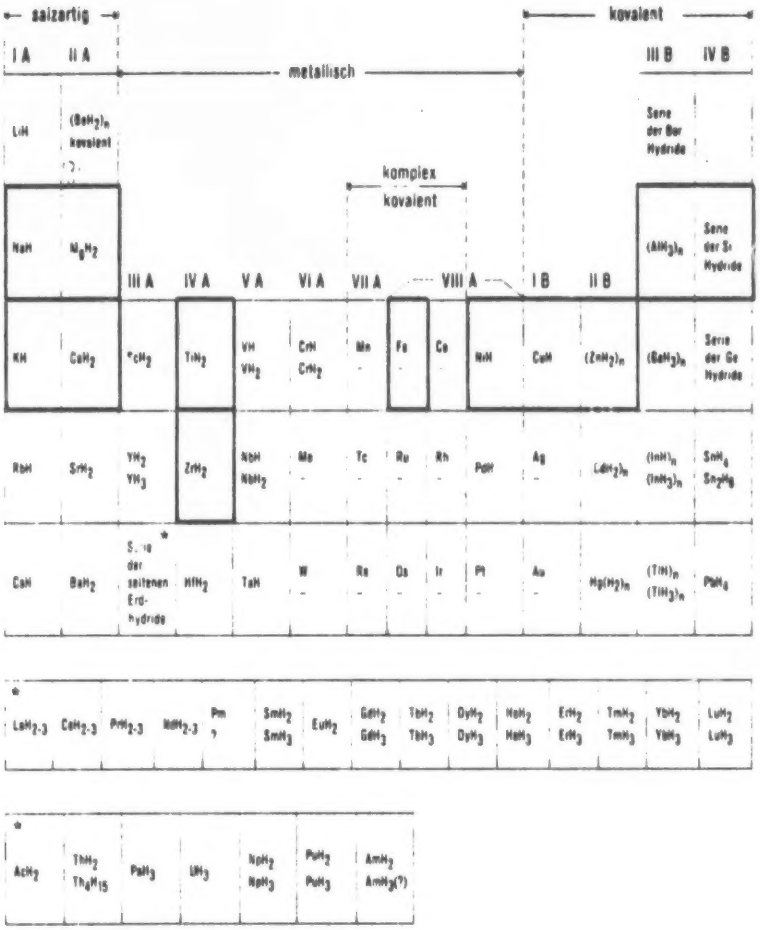
Some general characteristics of suitable storage hydrides may be formulated. The metal should be a lightweight element and easily available, for instance lithium, magnesium, calcium, titanium, iron or aluminium. The reaction enthalpy during the cycling of hydrogen should be within ± 40 kJ/mole H_2. If these limits are exceeded, practical problems arise with the regulation of the reaction heat flow.

In general, metal hydrides are exothermic on formation and endothermic on decomposition. Thus the waste heat of an engine could be used with advantage to extract the hydrogen from its hydride. This arrangement would use energy that is normally wasted into the atmosphere. Conversely, the same amount of energy in principle is released upon hydride formation, and this must be extracted during the recharging of the fuel tank in the vechicle.

The storage of hydrogen as a metal hydride involves a physical and a chemical process. Hydrogen atoms diffuse rapidly into the solid metal and react chemically to form a hydride.

Table 12-3

"Periodic Table" of hydrides (4).



saizartig		metallisch				komplex kovalent				kovalent			
I A	II A											III B	IV B
LiH	$(BeH_2)_n$ kovalent (?)											Serie der Bor Hydride	
NaH	MgH_2	III A	IV A	V A	VI A	VII A	VIII A			I B	II B	$(AlH_3)_n$	Serie der Si Hydride
KH	CaH_2	ScH_2	TiH_2	VH VH_2	CrH CrH_2	Mn -	Fe -	Co -	NiH	CuH	$(ZnH_2)_n$	$(GaH_3)_n$	Serie der Ge Hydride
RbH	SrH_2	YH_2 YH_3	ZrH_2	NbH NbH_2	Mo -	Tc -	Ru -	Rh -	PdH	Ag -	$(CdH_2)_n$	$(InH)_n$ $(InH_3)_n$	SnH_4 Sn_2H_6
CsH	BaH_2	Serie der seltenen Erdhydride *	HfH_2	TaH	W -	Re -	Os -	Ir -	Pt -	Au -	$Hg(H_2)_n$	$(TlH)_n$ $(TlH_3)_n$	PbH_4

*														
LaH_{2-3}	CeH_{2-3}	PrH_{2-3}	NdH_{2-3}	Pm ?	SmH_2 SmH_3	EuH_2	GdH_2 GdH_3	TbH_2 TbH_3	DyH_2 DyH_3	HoH_2 HoH_3	ErH_2 ErH_3	TmH_2 TmH_3	YbH_2 YbH_3	LuH_2 LuH_3

*						
AcH_2	ThH_2 Th_4H_{15}	PaH_3	UH_3	NpH_2 NpH_3	PuH_2 PuH_3	AmH_2 AmH_3(?)

The thermodynamics of the process are conveniently illustrated in a composition-pressure isotherm (CPI-diagram), which is determined experimentally, Figure 12-4. The maximum amounts of hydrogen which can be sorbed are given by the hydride formula of the metal, for instance MgH_2, $FeTiH_2$ and Mg_2CuH. Actually, some metal hydrides may contain more hydrogen atoms per volume than is the case for LH_2, Table 12-4.

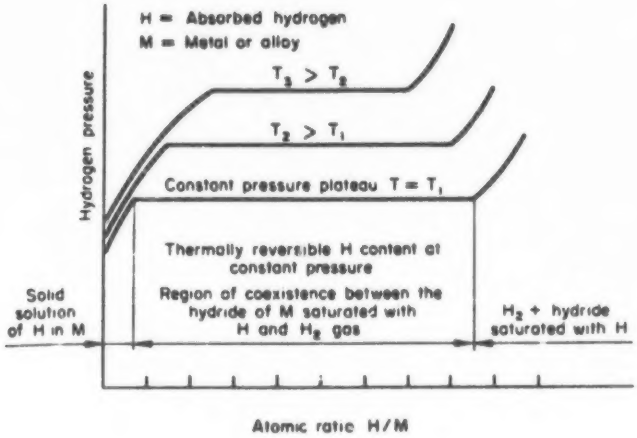


Figure 12-4

Composition pressure isotherms (CPI) (6).

Table 12-4

Relative hydrogen density of various substances.

	Density g/cm^3	Weight percentage hydrogen
LH_2 (liquid hydrogen)	0.07	100.0
NH_3 (ammonia)	0.6	17.7
LiH	0.8	12.7
MgH_2	1.4	7.6
TiH_2	3.8	4.0

Practical considerations regarding automobile performance impose certain requirements on the thermodynamics of an "ideal" hydride. The equilibrium pressure should be sufficiently high ($\lesssim$ 0.1 MPa) even under cold starting conditions (external temperatures as low as -30°C). The pressure at working temperatures (50 - 100°C) should not exceed 1 - 2 MPa. The hydrogen concentration should be around 5 - 10 % by mass. The reaction enthalpy should be below about 40 kJ/mol H_2. The heat transfer coefficient within the bed should approach that of a metal.

Each propulsion system requires its own "ideal" hydride. For instance, an automobile with an IC engine must achieve a successful cold start. Then as the engine approaches working temperature, the amount of waste heat flux and its temperature level must be compatible with the hydride bed at reasonable pressure levels. The pressure in the hydride remains constant (at the selected working temperature) as long as the hydrogen is delivered. The time required to refill the tank will diminish with increasing hydrogen pressures. From a practical point of view the tank design pressure should be kept below 10 MPa.

An ideal hydride is difficult to find. Figure 12-5 gives some indications of "ideal" thermodynamic characteristics for certain propulsion modes as well as commercial hydrides. Practical solutions must often rely on auxiliary equipment such as separate cold-starting devices or "hybrid hydride" systems consisting of separate hydride containers with different hydrides, Figure 12-6. Combinations of LH_2 and hydride systems have also been built, Figure 12-7. In this case the blow-off from the cryogenic tank is transferred to the metal hydride and saved for later vehicle operation.

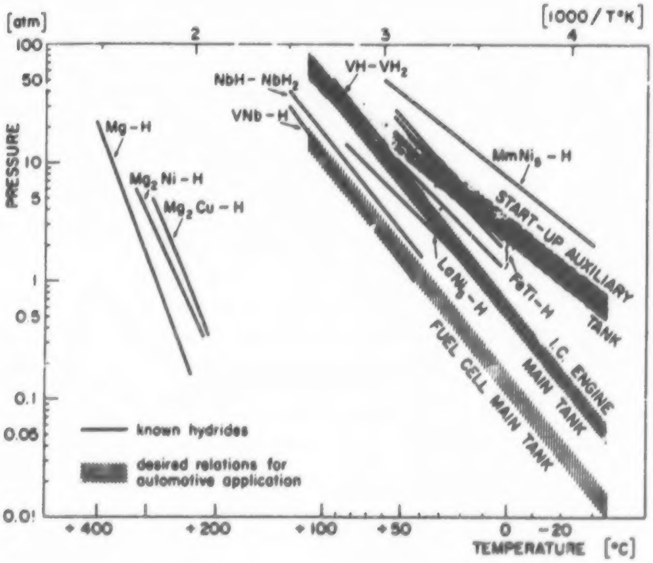
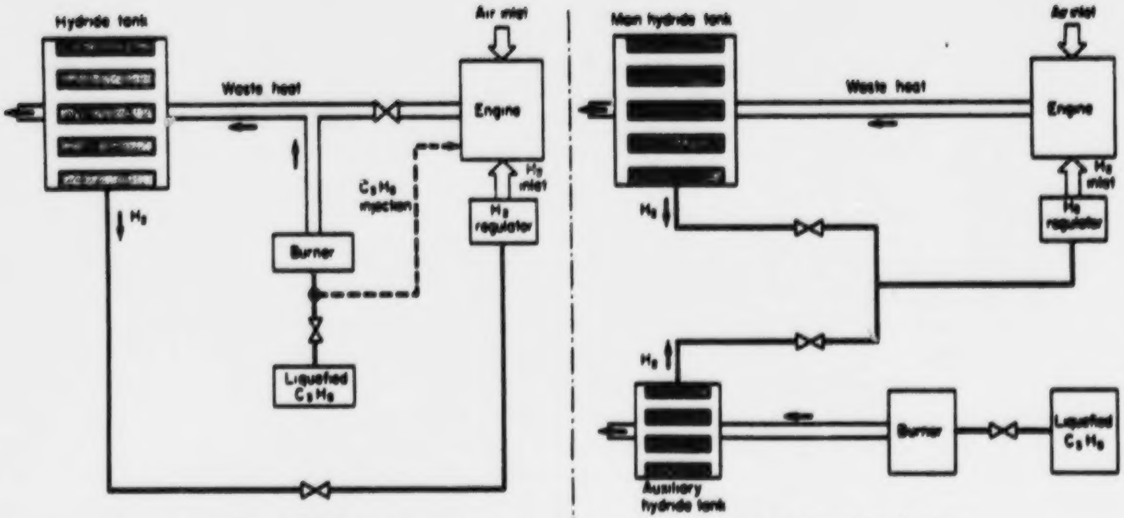


Figure 12.5

Equilibrium pressure-temperature relationsship (6).


Hydride tank
Waste heat
Air inlet
Engine
H_2 inlet
H_2 regulator
H_2
C_3H_8 injection
Burner
Liquefied C_3H_8
Main hydride tank
Waste heat
Air inlet
Engine
H_2 inlet
H_2 regulator
H_2
H_2
Burner
Liquefied C_3H_8
Auxiliary hydride tank

a) Use of a single hydride tank

b) Use of an auxiliary hydride tank

Figure-12-6

Practical solutions of hydride systems: cold-starting devices and separate hydride tanks (6).

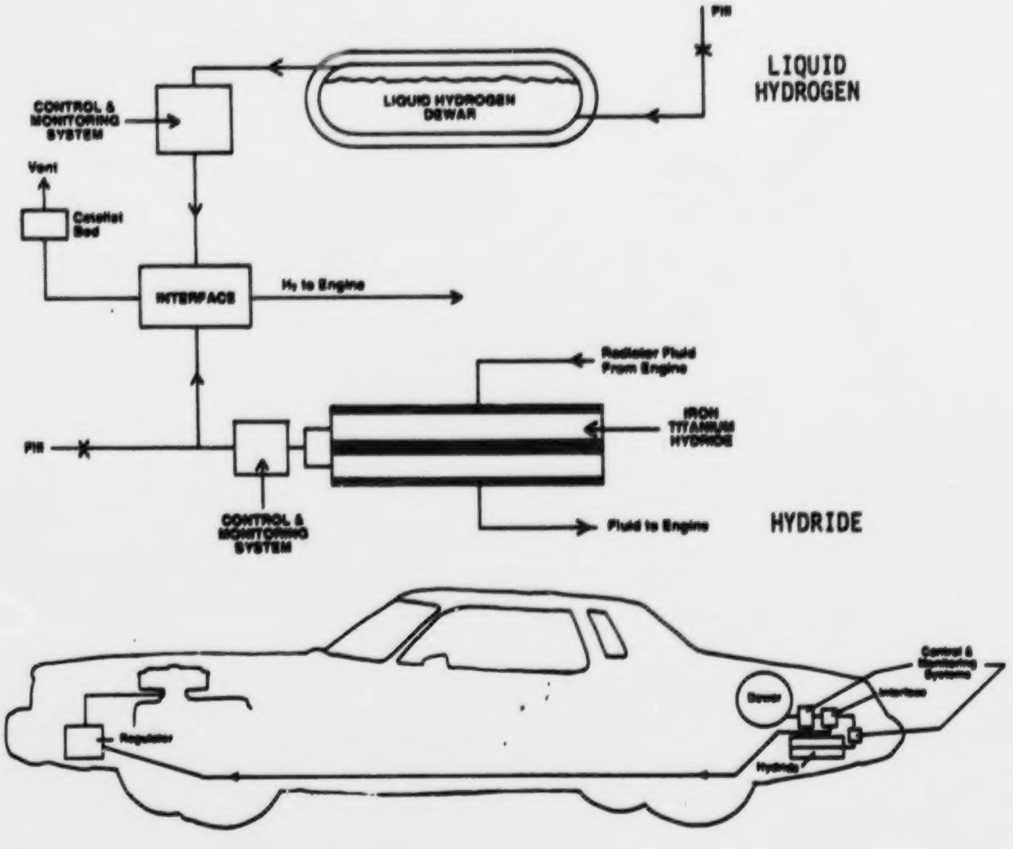

Fill
LIQUID HYDROGEN
LIQUID HYDROGEN DEWAR
CONTROL & MONITORING SYSTEM
Vent
Catalist Bed
INTERFACE
H_2 to Engine
Radiator Fluid From Engine
IRON TITANIUM HYDRIDE
Fill
CONTROL & MONITORING SYSTEM
Fluid to Engine
HYDRIDE
Dewar
Control & Monitoring Systems
Interface
Hydride
Regulator

Figure 12-7

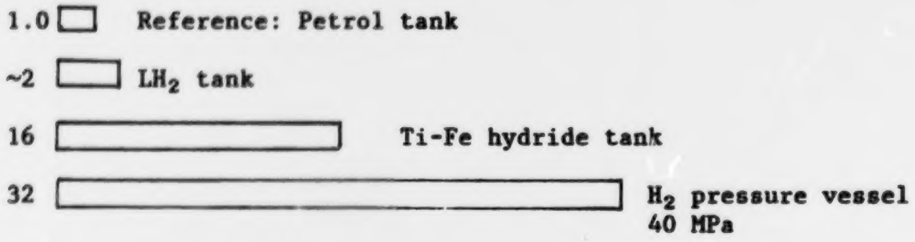
Combination LH_2 and hydride tank (7).

Table 12-5, taken from (4), shows mass and volume comparisons for different automotive hydrogen storage modes.

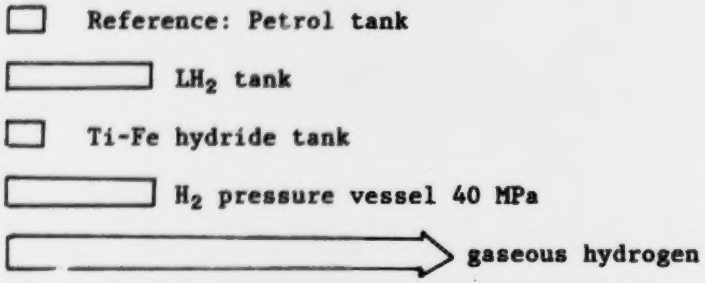
Table 12-5

Volume and mass comparisons for different fuels (4).

Mass comparison



Volume comparison



Specific example of mass comparison

	Volume dm^3	Mass kg	Mass incl. tank kg
Petrol	75.4	53.1	68
Methanol	147	117	141
H_2 pressure vessel 13.8 MPa	1820	19.5	2090
LH_2	275	19.5	136
Hydride Mg_2Ni/Mg_2NiH_4	132	233	284

There is thus a broad field of R & D options regarding hydrides, including system studies and optimization investigations of existent hydrides in practical designs adapted to different propulsion modes, the thermodynamics of ternary hydrides, high-reactive light hydrides as limiting cases, economics and safety of hydrides etc.

Considering the time scale of this study (→ year 2025), it is quite possible that entirely new or revived older systems for vehicular hydrogen storage or generation will become operative. Looking back, water reactive chemicals have long been used for the generation of hydrogen or hydrogen-rich compounds (8). At the turn of the century, several water-reactive materials were developed to generate hydrogen for commercial or military applications, such as LTA vehicles (Lighter Than Air), for example aluminium amalgamated with mercuric chloride, amalgamated magnesium, hydrone (an alloy of sodium with lead), hydrolith (containing primarily calcium hydride), hydrogenite (composed of ferrosilicon or ferromanganese), sodium hydroxide and slaked lime, and sical (containing sodium metal and aluminium silicide).

The role of water in these systems varies. Alkali metals use water as an oxidizer. With hydrides and carbides, water is involved in a hydrolysis mechanism. All of these systems may be considered as potential means of storing hydrogen on board. From a resource and energy utilization point of view, the chemicals should be generally available and their manufacturing energy requirements must be considered. As an illustration, the hypothetical reaction

$$2Fe + 3H_2O \rightarrow Fe_2O_3 + 3H_2$$

implies that 6 grams of hydrogen is generated from 176 grams of iron and water stored on board. The storage mass ratio of hydrogen is thus 3.4 %. If the on board storage of water could be dispensed with by collecting the engine exhaust water, the hydrogen storage ratio would be 5.3 %. The energy density of the fuel would be about 7300 kJ/kg (oxidizing iron), and thus such a system could be competitive to traditional storage systems. As regards the realization of reactions of the above kind, it has been a common experience that almost any metal can be made more or less reactive by special preparation or treatment, utilizing catalytic and/or surface effects.

Under extreme conditions, e.g. about 200 MPa and 4 K, hydrogen may become a metal. There have been suggestions that metallic hydrogen could be a superconductor with a critical temperature close to room temperature. Metallic hydrogen would be an ideal fuel with a density of about 600 kg/m^3, and this would lead to a revolution in hydrogen utilization (2 - 4). The metallic state could be metastable in the practical sense and thus analogous to diamond, which is not the lowest energy state of carbon but is formed at high pressures and remains stable when the pressure is released. During high pressure conductivity experiments with hydrogen an interesting hysteresis effect has actually been observed. Hydrogen did not immediately change into a dielectric when the pressure was reduced.

Other experiments (12) show that hydrogen becomes a solid at 25°C when subjected to a pressure of 5.7 GPa. The high pressure phase appears as a transparent crystalline mass. At higher pressures, 36 GPa, the density of the solid hydrogen was calculated to be around 600 - 700 kg/m^3, based on estimations of experimental refractive index data.

12.4 Technical aspects of hydrogen use in different transport modes

12.4.1 Land transports

12.4.1.1 Automobiles

In order to be operational, automobiles require the following supporting stakeholders: fuel producers, distributors and retailers, vehicle manufacturers, maintenance and repair facilities. The corresponding infrastructure network of today is firmly established and slow to change. A future change over to hydrogen as a transportation fuel would therefore be a protracted process because of the previous lack of an adequate logistics system.

Hydrogen-adapted engines have mostly been of the Otto type or, to a lesser extent, the Diesel type, although EC (External Combustion) engines could also be fuelled by hydrogen. In the long run, electrochemical converters (fuel cells) will probably replace heat engines. However, it is uncertain whether this will occur within the time scale of the current study (→ year 2025). Considering the problems of rigid infrastructure networks, it seems reasonable to assume that the adaption of known IC engines to hydrogen will be given priority.

In the past, hydrogen has occasionally been used as a fuel in IC engines. Often, hydrogen was a component in fuel gases produced from coal and used in stationary engines. In mobile units, hydrogen has been considered for certain LTA vehicles, together with oxygen in special air-independent applications (torpedoes), and generated on board in gasified-charcoal fuelled engines during periods of restricted petroleum availability.

In more recent times, a number of hydrogen engine developments were initiated by the growing concern about the enviroment. Projecting into the future, the interest in hydrogen engines is also associated with energy issues, such as supply independence and oil saving, and more efficient energy utilization in vechicles.

Although practically demonstrated, the hydrogen engine of today is technically rather undeveloped. Basically, the contemporary hydrogen engines are only suitably converted Otto or Diesel units, originally intended for hydrocarbon fuels. However, a broad field of R & D activities are aimed at an optimal hydrogen engine.

There are several physical and chemical properties of hydrogen which are quite different from those of conventional hydrocarbon fuels. For instance, its high gravimetric (142.5 MJ/kg) but low volumetric (12.77 MJ/m^3) heating value has implications for on board storage. A most significant characteristic which affects engine function is the laminar (or in some cases turbulent) flame speed. The flame speed of hydrogen is several factors higher than that of hydrocarbons. Moreover, it retains a useful flame speed in a very lean region. A fundamental requirement for an effectively functioning Otto engine is a reliable flame spread (deflagration wave) from the spark plug throughout the combustion space. Unfortunately, a safe flame spread, when using hydrocarbon, requires an almost stoichiometric air-fuel composition throughout the operational area. This results in unwanted exhaust gases that are hard to control. Moreover, deviations from the ideal Otto cycle will also be considerable, resulting in lower efficiencies. On the other hand, the ability of hydrogen to undergo lean combustion is of fundamental importance for a high thermal efficiency and low emission of unwanted substances.

As mentioned above, the hydrocarbon Otto engine is run with an almost constant equivalence ratio. Variable power requirements are met by trottling, which may be termed "quantity control". On the other hand, a hydrocarbon Diesel engine may be run by "quality control" because the fuel-air mixture autoignites in the hot compressed air. This process, mainly controlled by mixing and temperature levels, is achieved within wide equivalence ratios. However, because of its wide flammability limits, a hydrogen Otto engine may also be run using "quality control". This means that the output power is regulated by varying the equivalence ratio, which is illustrated in Figure 12-8 (13). The solid lines indicate quality control operation for both hydrogen and petrol. The wide difference for the two lean misfire positions should be noted. Normal petrol operation (quantity control) is also shown. Thus with hydrogen a high indicated thermal efficiency is possible, especially at part-loads. As shown further on, the largest quantity of fuel in the transport sector is consumed in intraregional transport using automobiles. The corresponding driving patterns are characterized by generally low engine part-loads; this is a very unsatisfactory performance domain for ordinary hydrocarbon Otto engines from an energy utilization point of view. A switch to hydrogen fuel for Otto engines is thus potentially advantageous in this respect.

Figure 12-8 also illustrates some drawbacks with the hydrogen Otto; the maximum IMEP for hydrogen is only about 75 - 80 % of the peak value for petrol. Indicated Mean Effective Pressure, IMEP, can be equated to the engine work per cycle for a given displacement engine. It is directly proportional to the engine torque and thus to the power output at a fixed engine speed. Generally, indicated values assume zero friction. The limited power is mainly due to the low density of hydrogen. Under stoichiometric conditions, the hydrogen occupies about 30 % of the cylinder volume, while a petrol charge occupies only a few percent. Thus the absolute value of energy available is lower in the hydrogen case. For equivalent powers, larger engine displacements are needed in the hydrogen case. However, this problem may be circumvented by using hydrogen in a Diesel-like operation where the hydrogen is injected directly into the cylinder. Preliminary investigations show that a 10 - 15 % (13) additional power increase over the corresponding hydrocarbon version is possible. Supercharging, air-cooling by means of cryogenic hydrogen and water injection are other alternative ways of increasing the inducted mass and thus the engine power.

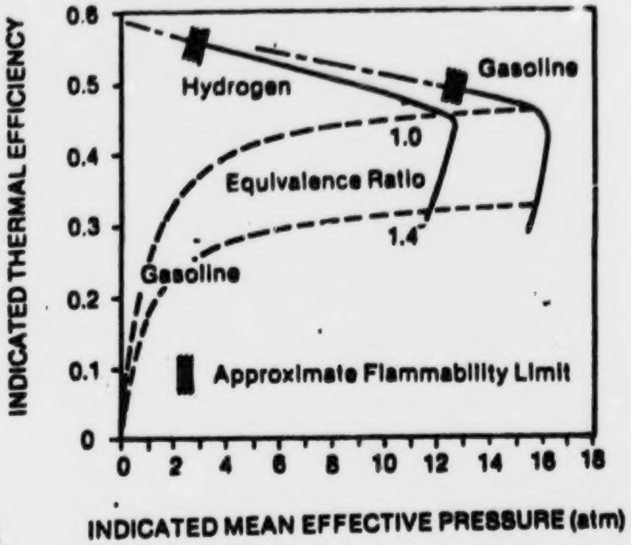


Figure 12-8

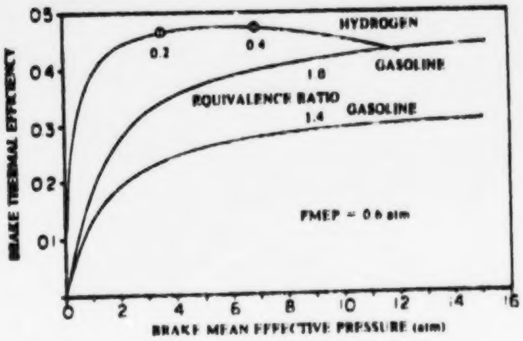
Fuel/air cycle performance for gasoline (= petrol) and hydrogen at a compression ratio of 10 (indicated basis) (13).

From a practical point of view, there are several problems, unique to hydrogen, which are difficult to deal with theoretically. Some of these are related both to engine design and to the properties of hydrogen, such as its extremely low ignition energy and small quenching distance. For instance, back-firing has been widely encountered in engines with a carburation type of hydrogen introduction. The tendency to backfire is, however, effectively countered by exhaust gas recirculation, water injection and the use of direct cylinder injection. Sometimes cylinders may fire prior to the spark discharge. Usually this is caused by hot metal parts or particulates from oil residues. Modifications to the cylinder and piston design and lubricating oil composition may improve the performance in this respect. Developments in the fields of low friction and temperature-resistant polymers may bring forth compounds suitable for covering friction surfaces inside the engine. It is possible that the lubricating oil may be entirely dispensed with. Not only will engine friction losses be lowered but also the hot-spot residues will be eliminated and certain emission characteristics will be improved.

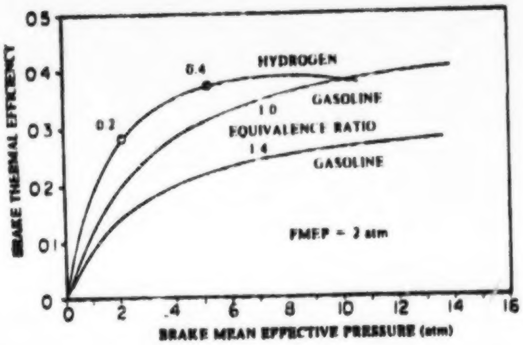
Initiated by the spark, the combustion in the hydrogen engine proceeds at a much higher rate than with petrol. This produces pressure rises which are sometimes equated with "knock". However, in an operating engine, the flow and combustion processes in the vicinity of the spark plug are most complex. A spark plug may misfire, preignite or discharge for several degrees of crankshaft rotation. It is thus not possible to separate the elements in a process consisting of spark plug firing, the growth of a flame kernel and its interaction with a turbulent flow field and subsequent transition to a flame front. Each successive kernel which is formed and emerges from the spark is immersed in a different flow field owing to the random variations in turbulence intensity. The macroscopic effects of these processes, which also depend on the air-fuel ratio, may result in variations in the rate of pressure rise, in the peak cylinder pressure and in engine output. This could be a field for future R & D efforts in the drive to produce an optimal hydrogen engine.

Turning now to the hydrogen engine efficiency, from a practical point of view, the "indicated" performance mentioned above must be translated into brake thermal efficiency, which is the efficiency actually produced at the engine output shaft. In principle, the Indicated Mean Effective Pressure minus the Friction Mean Effective Pressure equals the Brake Mean Effective Pressure. Further, indicated efficiency multiplied by mechanical efficiency equals brake efficiency. Figure 12-9 illustrates these concepts in a theoretical comparison between hydrogen and petrol engines. In general, hydrogen shows theoretical brake efficiences which are superior to those for petrol in a wide performance range. Researchers experimenting with engines converted to hydrogen usually also report significant gains in thermal efficiency by comparison with the petrol engines. This indicates that the engines were run in a very lean domain. Efficiency improvements of 20 - 50 % (4, 14) have been reported. However, some caution should be exercised when transforming these data into fuel consumption obtained in a real driving cycle.

Most of the exhaust products commonly encountered with hydrocarbon fuel are absent in a hydrogen engine exhaust. Traditional automobile exhaust contains carbon monoxide, innumerable hydrocarbons ranging from unreacted fuel to partially oxidized or pyrolyzed organic compounds, carbon dioxide, nitrogen oxides and, in certain cases, metal and halogen compounds. The hydrogen engine could possibly emit some hydrocarbon compounds originating from the lubricating oil. In a new or well-maintained engine this would probably be



Fuel/air cycle performance for petrol and hydrogen at a compression ratio of 10 for quality-controlled hydrogen and throttled petrol operation at low FMEP (brake basis).



Fuel/air cycle performance for petrol and hydrogen at a compression ratio of 10 for quality-controlled hydrogen and throttled petrol operation at high FMEP (brake basis).

Figure 12-9

Comparison of efficiencies of petrol and hydrogen engines (14).

of little concern, but the large oil consumption of worn engines may cause excessive PAH (Polynuclear Aromatic Hydrocarbon) emissions. Thus a development towards an oil-free engine could solve this problem.

The main unwanted emission component from a hydrogen engine consists of nitrogen oxides. The formation and emission of nitrogen oxides in combustion processes has been extensively investigated. Among other things, it has been established that the nitrogen oxide problem cannot be described with an "one-parameter" approach. Experiments have shown (13, 14) that a hydrogen engine may emit substantial amounts of nitrogen oxides near the stoichiometric equivalence ratio. At leaner ratios, which constitute a natural domain for the hydrogen engine, the emission falls to very low levels. Moreover, charge dilution by exhaust gas recirculation or water injection will also strongly suppress the nitrogen oxide formation.

12.4.1.2 Heavy duty vehicles

In contrast to private automobiles and light trucks, heavy duty vehicles are often used in fleet operations. This utilization mode is characterized by a refuelling from a central depot rather than from a chain of public filling stations. Moreover, fleet operators are mainly interested in the economics of purchase, maintenance and operation rather than psychological aspects of car ownership. As the present technology for hydrogen storage suffers from a weight penalty, it is best applied in fleet vehicles, where the weight disadvantage is less. The use of hydrogen in urban mass transit fleets would improve the environment quality of densely populated areas, thus helping to offset the initial costs in connection with the introduction of a new system. Experience from the management of hydrogen-fuelled fleets would be a great help in the subsequent establishment of a more general hydrogen distribution system; psychologically, it would help the general public, fleet operators and municipal authorities to adapt to the new method. A political decision to support hydrogen fuelled fleet vehicles could be one method of improving the environment. A debate is flourishing about whether air quality problems should be dealt with organisationally by limiting or forbidding petrol engines in city centres, or technologically by introducing lead-free fuels, such as liquid propane. The government may act by imposing suitable tax levels on different fuels, thus promoting certain directions of development.

In practical experiments for hydrogen bus programs (15 - 16), titanium-iron hydride is being used as the storage medium. A Daimler-Benz van carries 200 kg of hydride in a 65 litre container. The prototype has a working radius of between 100 and 150 km per recharge. Initial problems with excessive hydride reloading times have been overcome by shutting off the heat supply from the engine some time before refuelling. A combination of a low-temperature (titanium-iron) and a high-temperature (magnesium) hydride has given the Daimler-Benz vehicle ranges up to 400 km on a single charge from a 200 kg tank.

These research programs have also provided spin-offs for use in related fields. The titanium-iron system, for instance, may also be used as an air conditioning unit in the car because part of the heat needed to release the hydrogen can be taken from the air. Such a system may also be used for domestic heating and air conditioning. Moreover, in a city van fleet with a central refuelling depot, the heat energy released when recharging the hydride could be fed into the municipal heating system.

Regarding engine modifications, fuel metering may be achieved by using a propane carburetor adapted for hydrogen operation. (The original carburetor may actually be retained as a water injection device). In order to improve efficiency and power, new pistons should be installed and the cylinder heads should be milled down. In addition, the spark timing should be reset. Figure 12-10 from (16) shows a typical arrangement.

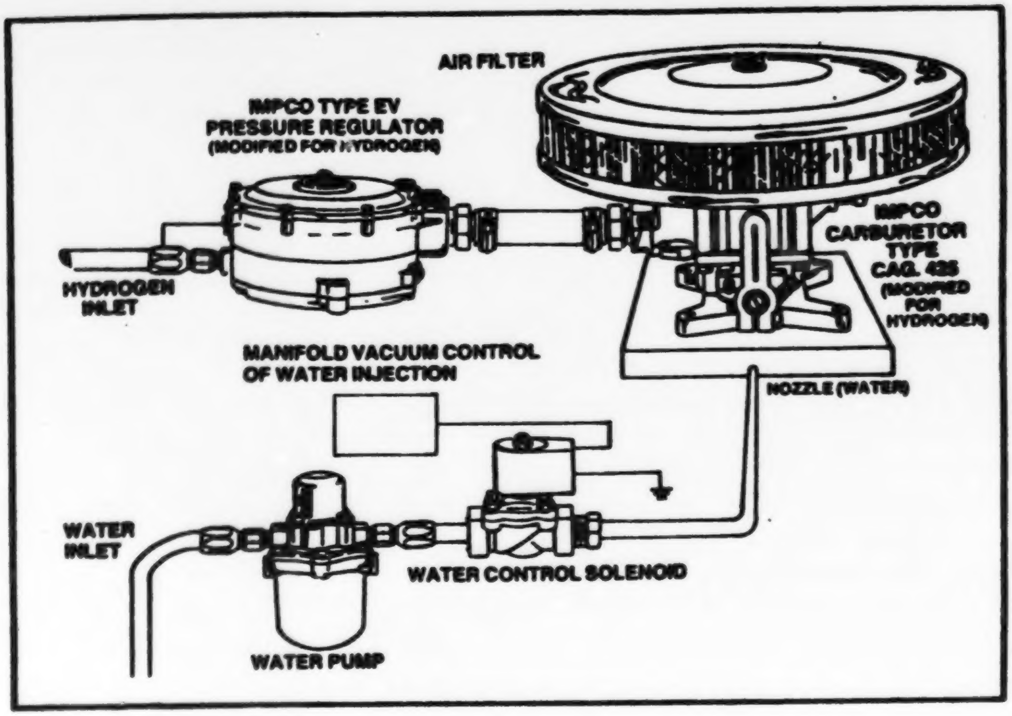

AIR FILTER
IMPCO TYPE EV
PRESSURE REGULATOR
(MODIFIED FOR HYDROGEN)
IMPCO
CARBURETOR
TYPE
CA.G. 425
(MODIFIED
FOR
HYDROGEN)
HYDROGEN
INLET
MANIFOLD VACUUM CONTROL
OF WATER INJECTION
NOZZLE (WATER)
WATER
INLET
WATER CONTROL SOLENOID
WATER PUMP

Figure 12-10

Hydrogen bus engine fuel system (16).

12.4.1.3 Railways

Railway trains have large freight volumes available, although their cross-sections are limited by existing tunnels, parallel tracks etc. The main propulsion units are Diesel engines, gas turbines or electric motors. Combinations, for instance Diesel-electric, are also used. Hydrogen is an alternative fuel for the heat-engine propelled trains. However, in general, hydrogen must face fierce competition from electricity, which is already in common use for railways and has a well developed infrastructure for its distribution and use. Moreover, electric power systems are energy efficient, evironmentally clean and silent at the power unit. The main drawbacks of electricity for use on railways are high investment costs and the existence of low traffic density regions where electrification is impractical.

A hydrogen-powered train may carry a sufficiently large fuel supply in order to be able to operate between distant fuelling depots. The carrying of LH_2 fuel should not pose any problems as railways have an established routine for the transport of cryogenic liquids. Futuristically, magnetic levitation has been considered for trains. The superconducting electromagnets use liquid helium as a coolant. If superconductors with higher transition temperatures should be developed, an interesting possibility could be to use hydrogen as both a magnet coolant and a fuel.

12.4.2 Aircraft applications

In contrast to the automobile sector, which requires a fuel distribution network ending in a large chain of public filling stations, the civil flight sector is principally concentrated to a few airport terminals. Commercial aviation is a complex, capital and energy-intensive system with several stakeholders: airlines, aircraft manufacturers, airport operators, oil companies, governmental institutions and consumers. The freedom of choice of energy supply systems is restricted because air travel is international and because aircrafts are designed to use a specific fuel of a rather narrow composition. For a small country like Sweden, some important facts must be recognized. Most commercial aeroplanes are of foreign manufacture, and judging from the current debate on the future of the Swedish aeronautical industry, this will continue to be the case. The fuel consumption in Swedish domestic flights is limited and of about the same order as in leisure boating. From an energy utilization point of view, a transition to hydrogen fuel in domestic aircraft does not seem to be rewarding. However, refuelling of international flights in Sweden requires that the appropriate fuel should be available, and this could one day be hydrogen. This emphasises the need for international coordination in future aeronautic-hydrogen applications. Moreover, as mentioned elsewhere, the introduction of hydrogen fuelled transportation could start in the aeronautical field owing to the relatively few end-user locations (airports). Finally, the special properties of hydrogen are well suited for aviation uses.

Air traffic is becoming more and more sensitive to capital investments and operating costs for labour and fuel. Consequently a new air system that departs radically from the traditional one must offer significant and convincing performance increases in order to be accepted. A special character of commercial aviation is that several important components have a military origin. For instance, most commercial jet engines have been developed from a military design; this might have been a disadvantage since the military requirements for a jet engine differ in several respects from the requirements for the civilian type. Thus the attitude of the armed forces towards the use of hydrogen may be important. Military vehicles must conform to heavy demands on power, survivability and, to a lesser extent, fuel consumption. Emission levels are not significant, but logistics networks for vehicle maintenance and fuel supply are important. If the military side is not interested in the development of hydrogen fuelled aircraft, the burden on aircraft manufacturers will increase substantially. Because of enormous development costs, the cost per aeroplane is very sensitive to the number of planes sold. Each of the most recent generations of aeroplanes has required a development cost of about 1 G $ (1). At a sales price of 25 M$, 400 planes are needed to bring the average development costs down to 10 % of the sales price. Thus a decision to develop a new generation of planes involves a process that has been termed "betting the company".

Problems regarding the certification of an LH_2 aircraft and its fuel system should be investigated at en early stage. Although new components may be manufactured, the components and subsystems must be quality-tested and the performance, safety and reliability of complete systems must be demonstrated before flight testing can be carried out. It should be remembered that airworthiness regulations were developed for traditional jet fuels and may not be consistent with LH_2 fuel, a circumstance which could require time-consuming tailoring.

Figure 12-11 from (17) shows the relative importance of nominal airline costs for a typical aircraft (Boeing 717-200). These costs include airframe maintenance, flight crew, spares investment, flight attendants, aircraft service, landing fees, insurance, depreciation and fuel. However, when discussing the introduction of aircrafts which incorporate a new technology, special attention must be focused on the identification of "delay" costs. Figure 12-12, also from (17), shows current examples of annual costs of delay and cancellations. Even the introduction of new "traditional" aircraft types may lower the dispatch reliability to 90 - 93 % during the first year of use, which can have a disastrous effect on airline profitability. Thus the possible impacts in this respect of the introduction of hydrogen fuelled aircraft should be carefully investigated.

As regards the time span for commercial hydrogen flights, the new fuel must be available throughout the lifetime of the corresponding aeroplane. If design, certification, etc take about 10 years and the service life is about 20 years, obviously the decision to introduce a series of hydrogen fuelled aircrafts can only be taken if the hydrogen fuel is assumed to be freely available during the whole service period. Considering the big economic stakes involved, such a decision may exceed traditional planning routines. On the other hand, hydrocarbon fuel supplies may become very limited and could be reserved for special purposes. However, it is not unreasonable to assume that aviation could be given priority for petroleum fuels because of its special character in transportation. It is equally reasonable to assume that air travel will be judged to be less essential to national welfare and will be given less priority. Thus the future fuel supply issue for aviation is not self-evident.

Hydrogen technology in aerospace covers a velocity interval from subsonic to orbital speeds. Historically, in the US during the nineteen-fifties, an existing military jet aeroplane (the Canberra) was modified for liquid hydrogen use and successfully flown (18). In the sixties, some basic research was done on hypersonic, airbreathing flight using hydrogen. Apart from being an ideal propulsion fuel for supersonic combustion ramjets, liquid hydrogen is a perfect coolant for engines and aeroplane structures at hypersonic speeds. Progress in hydrogen technology permitted its use in the Saturn project, and hydrogen will also be used in the Space Shuttle.

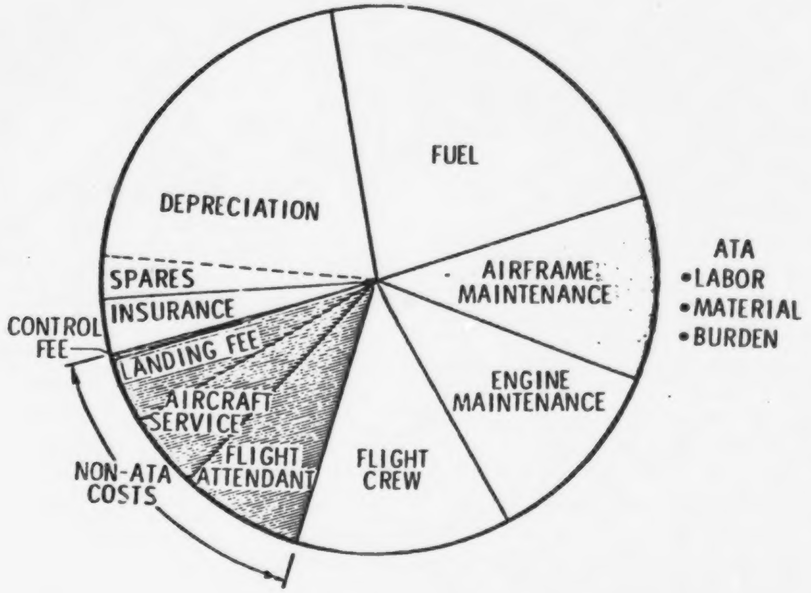


Figure 12-11

Aircraft-related operating expenses (17).

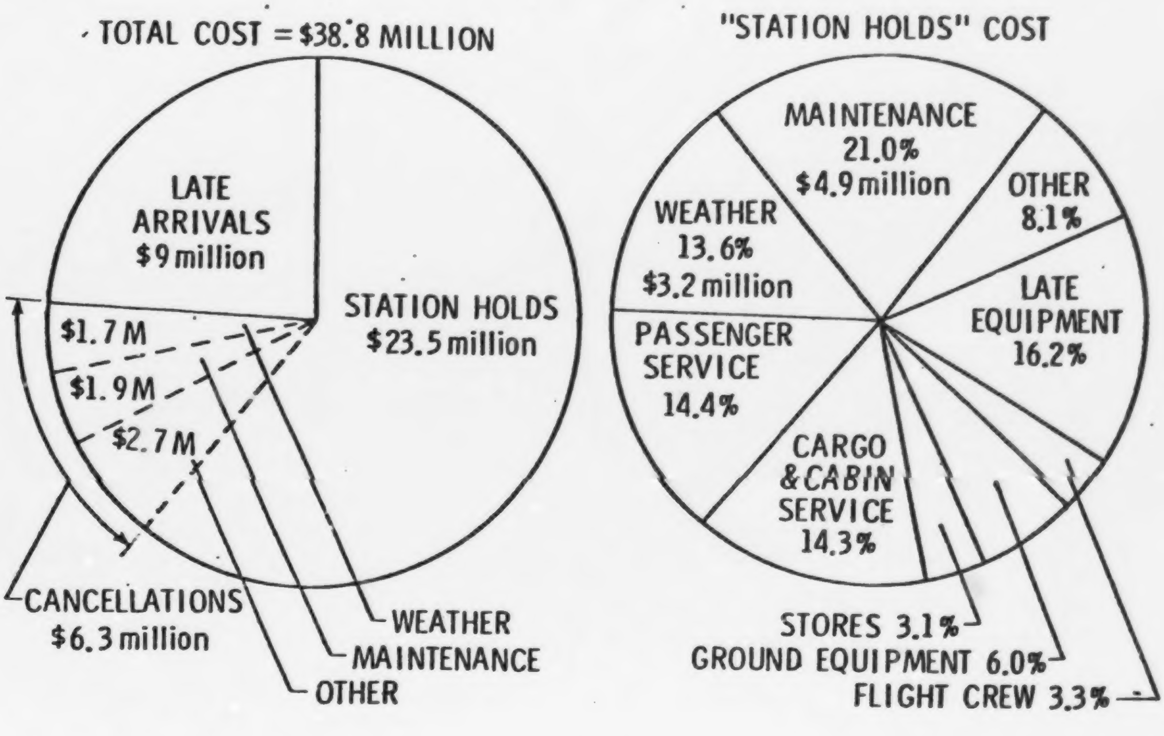


Figure 12-12

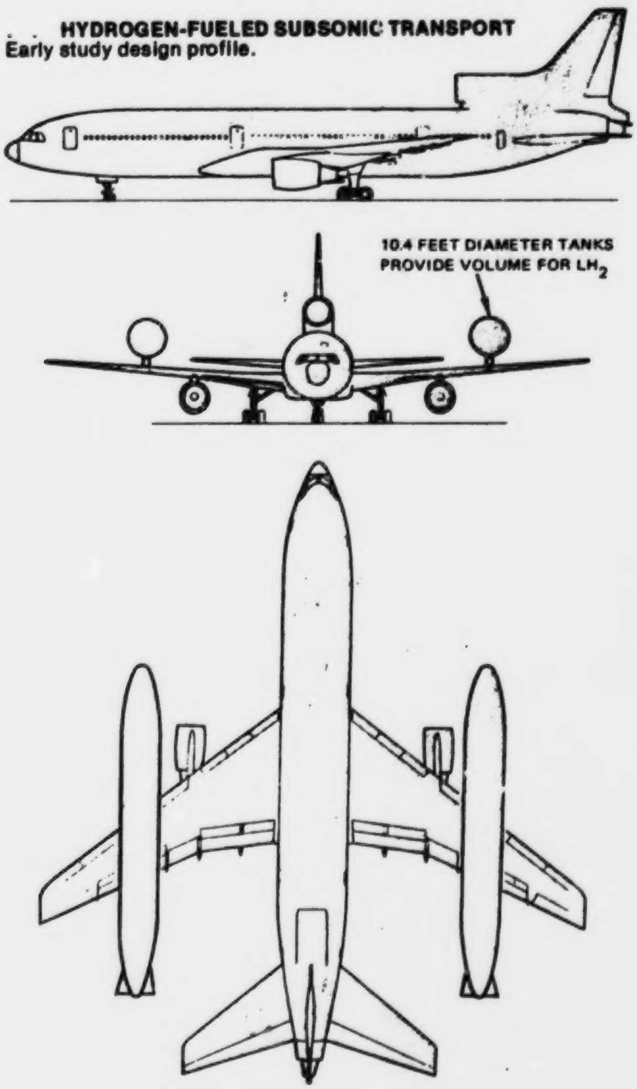
Annual cost of delay and cancellation to American Airlines (1976 dollars) (17)

The US space program has made hydrogen routinely acceptable to flight and ground crews. But in order to be acceptable to the air traveller, some psychological barriers concerning hydrogen safety must be overcome. Although farfetched, the loss of the airship Hindenburg is still partly associated with "aviation" and "hydrogen" by the general public, while the use of traditional fuels has a well-documented history of safety for passengers and other people.

The aeroplane design of today is strongly tied to the use of hydrocarbon jet fuel. In contrast to these performance and weight oriented designs, the hydrogen aeroplane is volume oriented. Reference (19) gives some comparisons between JP fuelled and LH_2 fuelled subsonic and supersonic transport (Figures 12-13 and 12-14). In general, for equal payloads, ranges and speeds, the hydrogen aeroplane has a substantially lower gross weight and fuel weight and thus a better energy utilization.

As regards turbojet engines, a modification to permit the use of gaseous hydrogen fuel was demonstrated in the mid-fifties. The liquid hydrogen was vapourized before it entered the combustion chamber, Figure 12-15 (20). Special characteristics of a hydrogen fuelled turbojet are: Short combustor lengths because of high diffusivity and mixing, smooth ignition and uniform temperature profiles which minimize thermal stresses, low emissivity of the flame thus reducing radiant heat transfer, no impurties and thus less high temperature corrosion phenomena. These factors will also improve the life of turbojet engine components and therefore also reduce maintenance requirements. In particular, the eagerly awaited ceramic turbine could be feasible. The major obstacles to ceramic turbine components are uneven thermal stresses and impacts from carbon-type deposits. If the ceramic turbine concept could be combined with hydrogen propulsion, the performance of turbojet engines (and all gas turbines) would be greatly enhanced. Fundamentally, this is due to the possibility of designing a "stoichiometric gas turbine" with extremely high combustion temperatures.

There should also be prospects for drag reduction by cooling for cryo-fuelled aircraft. A cooled laminar boundary layer at subsonic and low supersonic speeds is more resistant to the transition to turbulent flow. Thus there is a possibility of laminarization by cooling, with a consequent reduction in skin friction drag. This would be achieved by letting the cryo-fuel flow through coooling channels in the surface of selected aeroplane structures, such as wing, fuselage and pods, on its way to the engines. Obviously a cooling system brings with it a weight penalty, which somewhat counteracts the potential fuel saving.


HYDROGEN-FUELED SUBSONIC TRANSPORT
Early study design profile.
10.4 FEET DIAMETER TANKS PROVIDE VOLUME FOR LH_2

SAMPLE JP- VS. LH_2-FUELED SUBSONIC TRANSPORTS
Current technology.

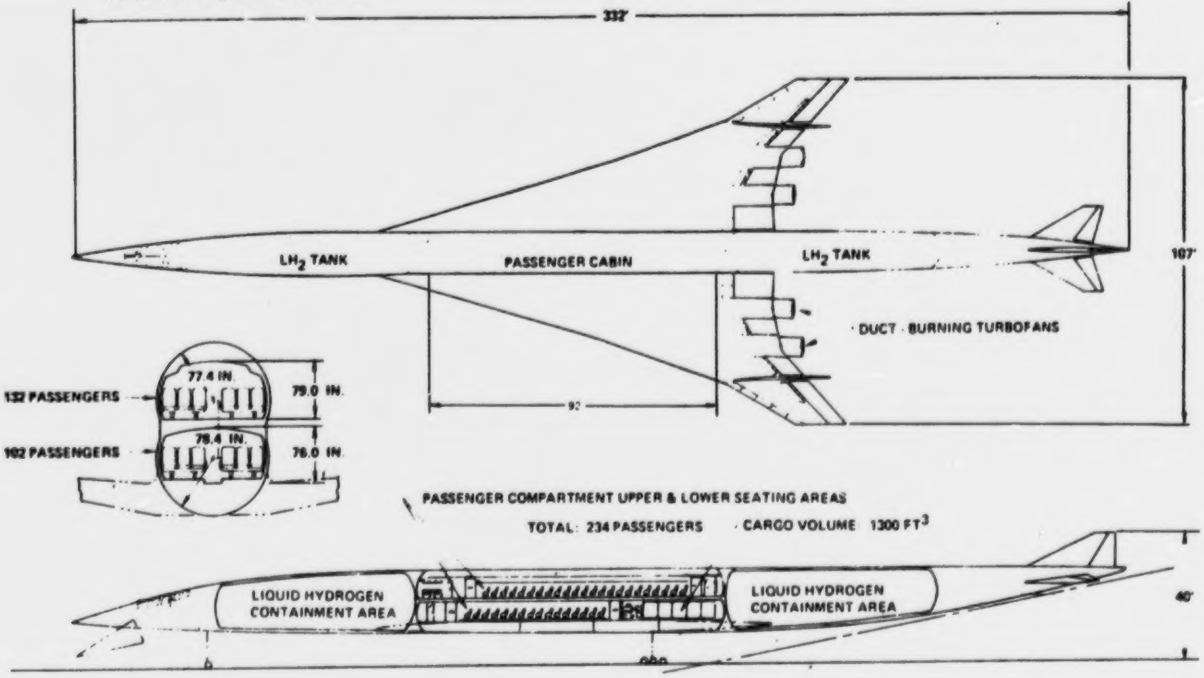
		JP FUELED SUBSONIC TRANSPORT	LH_2 FUELED SUBSONIC TRANSPORT	% CHANGE
PAYLOAD*	LB	56,000	56,000	
RANGE	N MI	3,400	3,400	
CRUISE SPEED	MACH	0.820	0.820	
GROSS WEIGHT	LB	430,000	318,000	-26
O. E. W.	LB	239,200	215,350	-10
FUEL WEIGHT (CAPACITY)	LB	137,000	46,650	-65.9
FUEL VOLUME	CU FT	2,920	11,050	+278
WING AREA	SQ FT	3,460	2,830	-18.2
WING SPAN	FT.	155	140	
WING LOADING	LB/SQ. FT.	124	113	
THRUST/WEIGHT (SLS)		0.292	0.396	
L/D		15.5	12.6	
SFC	$\left(\frac{LB}{HR}\right)/LB$	0.677	0.216	

*272 PASSENGERS PLUS 1600 LB. CARGO

Figure 12-13

LH_2 subsonic transport (19).

HYDROGEN-FUELED ARROW-WING SST CONCEPT
Recent study design profile.


332'
LH$_2$ TANK
PASSENGER CABIN
LH$_2$ TANK
107'
DUCT · BURNING TURBOFANS
92'
77.4 IN.
79.0 IN.
132 PASSENGERS
76.4 IN.
76.0 IN.
102 PASSENGERS
PASSENGER COMPARTMENT UPPER & LOWER SEATING AREAS
TOTAL: 234 PASSENGERS
CARGO VOLUME 1300 FT^3
LIQUID HYDROGEN CONTAINMENT AREA
LIQUID HYDROGEN CONTAINMENT AREA
40'

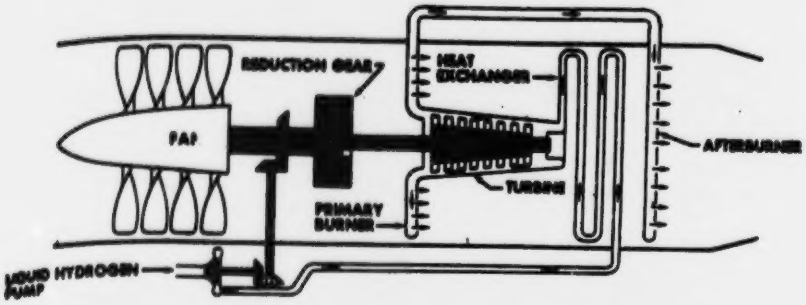
SAMPLE JP- and LH$_2$-FUELED SUPERSONIC TRANSPORTS
1981 technology.

- PRELIMINARY DATA -

		JP FUELED SST	LH$_2$ FUELED SST
TAKEOFF GROSS WEIGHT	LB	750,000	379,000
OPERATING EMPTY WEIGHT	LB	309,70)	232,000
FUEL WEIGHT	LB	391,300	98,000
FUEL VOLUME	FT^3	8,290	2,210
WING AREA	FT^2	10,822	7,580
SPAN	FT	132.5	107
OVERALL LENGTH	FT	297	332
THRUST PER ENGINE (SLS)	LB	89,500	47,350
SPECIFIC FUEL CONSUMPTION (CRUISE)	(LB/HR)/LB	1.51	.561
ENERGY PER SEAT MILE	BTU/SEAT n mi	8102	4375

Figure 12-14

LH$_2$ supersonic transport (19).



Model 304 engine schematic.

Figure 12-15

Turbojet modification for LH_2 use (20).

Turning now to jet engines for hypersonic aeroplanes, there is a speed level at which the turbojet engine has to be replaced by a ramjet engine because of temperature limitations imposed by turbine materials. Again, ceramic materials may raise the transition speed level. However, at sufficiently high flight Mach numbers ($M \sim 6 - 8$) the thermal conditions will be too extreme even for ordinary ramjets. In this case supersonic combustion may be introduced. Theoretical and laboratory investigations show definite advantages for hydrogen fuel in the SCRAM-jet (Supersonic Combustion Ram Jet). Although efforts in realizing the SCRAM-jet have been underway since the sixties, no practically working unit has yet been demonstrated.

The introduction of LH_2 fuel into air transportation will require profound changes in traditional airport equipment and operations. Provided that hydrogen is supplied to the airport region through pipelines, on-site liquefaction and storage plants will be required, and refuelling equipment and new aircraft maintenance facilities will be needed. The safety aspect is of course an important boundary condition in all these new systems.

Figure 12-16 shows LH_2 fuel facilities at an airport schematically (21). Hydrogen arrives through a pipeline, is liquefied and stored in cryogenic vessels. LH_2 is continuously circulated around the terminal in pipelines that are located in open trenches or buried in positively ventilated tunnels. It is estimated that about 15 percent of the LH_2 supplied to the aeroplanes will vapourize. This gaseous hydrogen is collected and reliquefied.

Figure 12-17, also from (21), shows the aeroplane refuelling equipment. The terminal pipeline is provided with a sufficient number of LH_2 outlet valves. A hydrant truck connects the pipeline to the aeroplane. Two lines are connected, one for LH_2 delivery and one for H_2 vapour return. Helium, carried in pressure vessels on board the truck, is used for purging the lines. The H_2 vapour line will also collect the purge helium so that this expensive gas is partly recovered. The capital investments for this kind of LH_2 ground system, applied to the Chicago O'Hare International Airport and San Fransico's International Airport, have been estimated to be 469 and 340 million US dollars, respectively (21).

Other alternative support systems for airports are equally possible. For instance, if hydrogen is liquefied near the terminal, it may be transferred by trucks to the aeroplanes for refuelling. Although the economics of different LH_2 systems are important, the safety aspect is a prime consideration and has yet to be determined for each alternative.

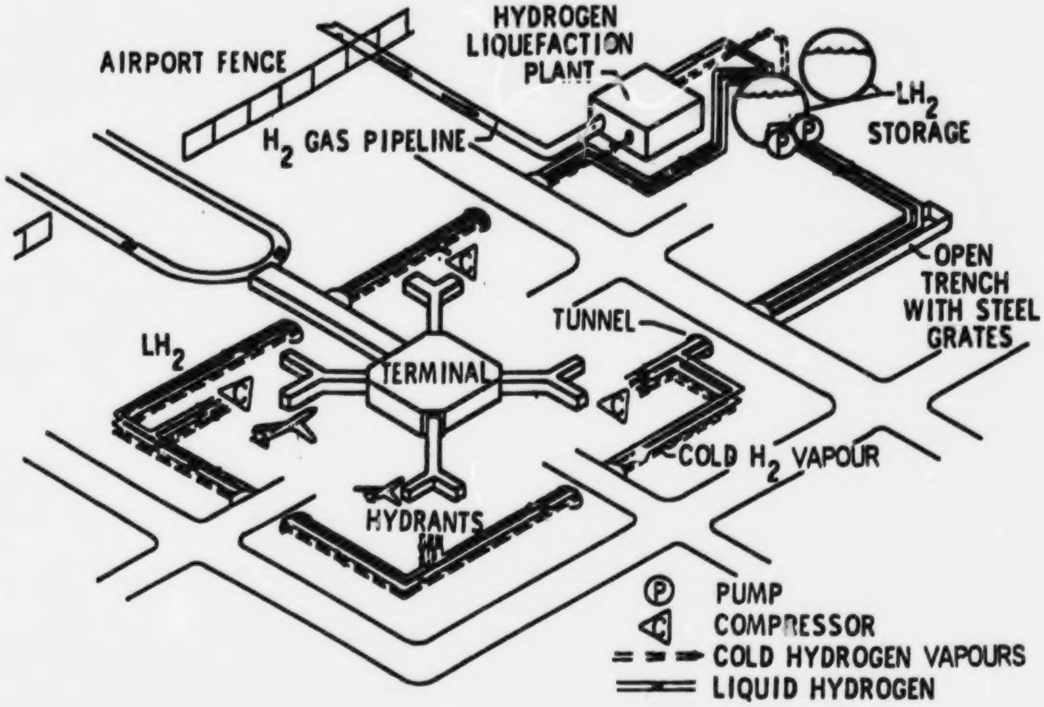

HYDROGEN LIQUEFACTION PLANT
AIRPORT FENCE
H_2 GAS PIPELINE
LH_2 STORAGE
P
OPEN TRENCH WITH STEEL GRATES
TUNNEL
LH_2
TERMINAL
C
COLD H_2 VAPOUR
HYDRANTS
PUMP
COMPRESSOR
COLD HYDROGEN VAPOURS
LIQUID HYDROGEN

Figure 12-16

Schematic diagram of a hydrogen liquefaction, storage, and distribution system at an airport (21).

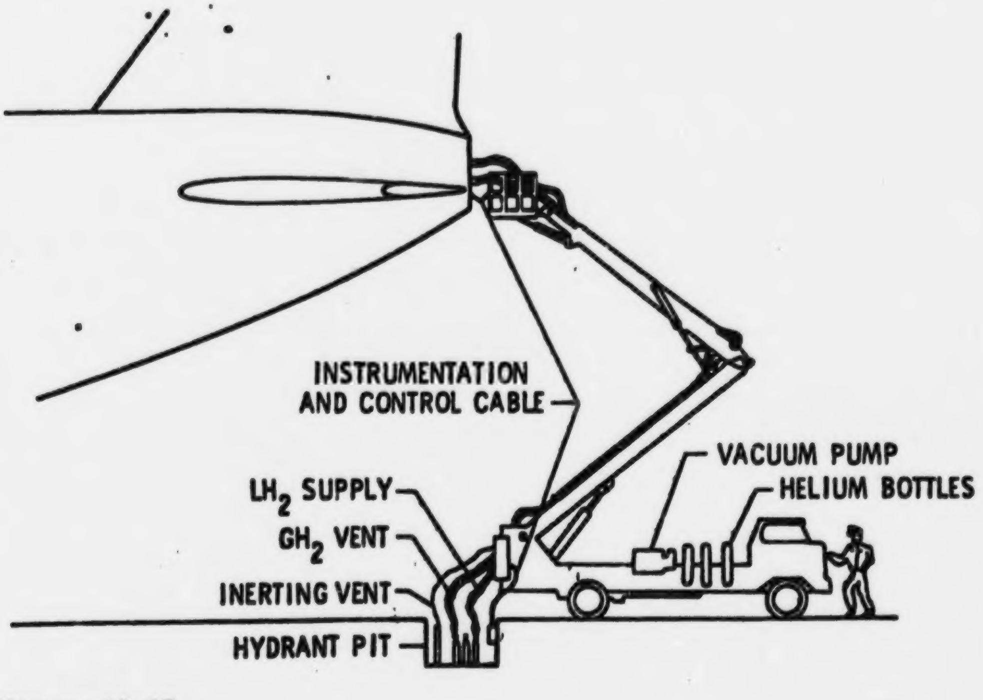

INSTRUMENTATION AND CONTROL CABLE
VACUUM PUMP
HELIUM BOTTLES
LH_2 SUPPLY
GH_2 VENT
INERTING VENT
HYDRANT PIT

Figure 12-17

Fuelling of an aircraft with LH_2 via hydrant truck (21).

From the air-traveller's point of view, the important factors are safety, service and cost. The safety aspects as they affect the customer are yet to be determined. As regards service, there could be some inconvenience especially during the early stages of LH_2 fuel introduction. The aircraft using these fuels can only fly between locations where LH_2 is available. Obviously, this requires thorough international cooperation in order to make LH_2 airlines feasible.

As a starting point in a development towards commercial LH_2 air operations, it is suggested in (22) that an experimental airline should be organized and operated under government sponsorship for at least 2 years. The airline would use four LH_2 fuelled wide-body aircrafts to carry commercial cargo between the United States, Western Europe and the Middle East. The route involving the corresponding four cities is illustrated in Figure 12-18. These cities were suggested because significant volumes of air cargo are regularly transferred from each and because they are located in areas that have the potential for manufacturing hydrogen economically.

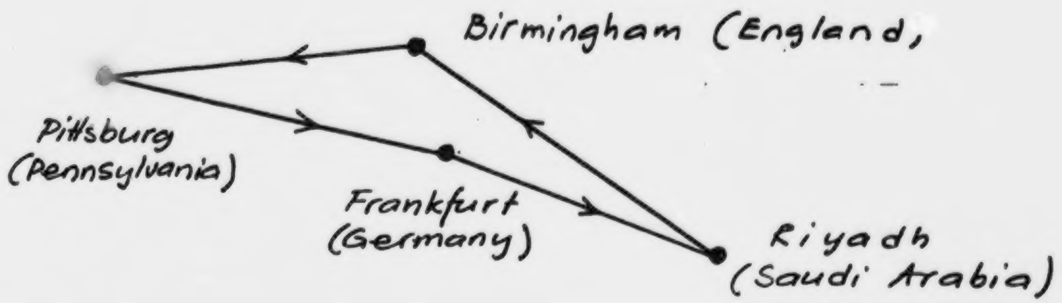


Figure 12-18

Operating terminals for a proposed experimental LH_2 airline (22).

12.4.3 Sea traffic

As hydrogen is an alternative fuel for almost any heat engine, the fundamental technical principles for land transport are also applicable for sea transport. However, by comparison with land transport, the dimensions and power levels of the sea-borne propulsion units are generally much higher, resulting in quite different fuel injection and combustion dynamics. Thus a technical extrapolation of hydrogen-converted small engines may require substantial tailoring. However, for ship propulsion, hydrogen will face competition from almost every other fuel (including nuclear power) except electricity. Ships are usually fuelled with Diesel oil or bunker (heavy grade) oil. Environmental pollution has not posed problems as ships travel far from population centres. In addition, the ocean-going ship operators are mostly outside governmental control and are therefore hard to influence towards farsighted goals and international cooperation. Moreover, the prospect of using cryogenic fuels in all ships should be approached cautiously from a safety point of view, as liquid natural gas has been observed to explode when poured onto water under certain conditions (3).

12.5 Competitors to hydrogen

Fuels for the transportation sector constitute a critical issue in energy supply scenarios, especially those describing alternatives to a petroleum primary energy supply. The change from oil as a major transport fuel to alternative sources may follow unconventional paths. It is not only a question of replacing old fuels with new ones; new systems must also be found which carry out transportation with applied boundary conditions. For instance, the hydrogen automobile may be motivated because of its cleanliness and efficient energy utilization. The development of batteries and fuel cells may lead to new concepts in automotive propulsion.

As mentioned elsewhere, in the history of transportation there are many examples of how new systems have replaced old ones. When petroleum fuelled automobiles replaced hay fuelled horses, there was no absolute shortage of hay or of horses. Similarly, the original price differences were not the main issue. Rather, the choice of equipment and fuel was determined by technological advances in propulsion processes.

When different transportation fuels are discussed, they are usually ranked according to price. However, two equally priced fuels may not be equivalent as regards processes, equipment and purpose. Moreover, in a transition, the prospective fuel candidates will probably be backed up with varying intensities by the stakeholders in the competition. This process may, as history shows, lead to new and imaginative modifications or solutions to transport problems. Hydrogen, for instance, may offer not only thermal energy but also prospects of developing new items related to fuel cells. The methods which are economically most attractive for transforming chemical energy into electric energy have hitherto utilized the intermediate step of uncontrolled combustion. Already in 1894, Ostwald advocated the replacement of the heat engine by the carbonoxygen fuel cell, but a practical unit is still lacking. If new and better fuel cell processes are invented which centre around the use of hydrogen (or any other energy carrier), this will promote the adoption of the fuel itself. Such a course will be determined not only by the actual price but also by benefits which may not simply be limited to the fuel price.

In Figure 12-19, the primary energy sources specified for this study are tabulated. The table includes hydrogen, other competitive transportation fuels that are compatible with the primary energy source and different types of end-user engine. If the petroleum primary energy source is replaced by an alternative, there is obviously a wide range of possible energy carriers for different propulsion systems. One problem in the evaluation of competing alternatives is that beyond the year 2000 end-user processes may be entirely different from present-day methods. By comparison with improvements in the utilization of energy in extrapolated existing equipment, innovations in basic processes or overall transportation requirements and structure may bring forth profound changes.

Extrapolating into the future, some domains for combustion research with a possible revolutionary impact on the choice of fuel and engines for the transportation sector are discussed briefly below.

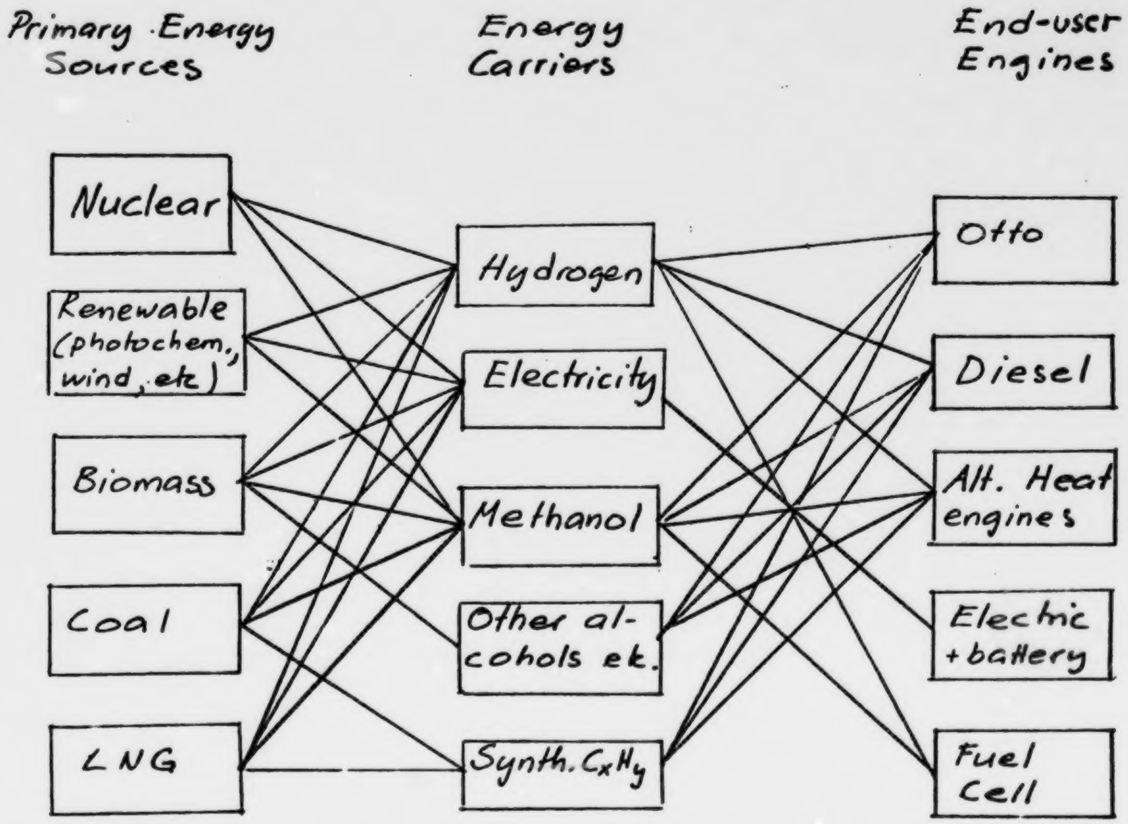

Primary Energy Sources
Energy Carriers
End-user Engines
Nuclear
Renewable (photochem., wind, etc)
Biomass
Coal
LNG
Hydrogen
Electricity
Methanol
Other alcohols etc.
Synth. C_xH_y
Otto
Diesel
Alt. Heat engines
Electric + battery
Fuel Cell

Figure 12-19

Survey of alternative paths from different primary energy sources to end-user engines.

Lean combustion has implications with regard to both pollutant emissions and engine efficiency. Actually, the favourable qualities of hydrogen as an engine fuel depend on its unique property of lean combustion compared to hydrocarbons. Lean combustion is associated with flammability limits, but then again progress in catalytic processes and the use of catalytic phenomena may circumvent these limitations. As catalytic effects are closely related to surface structure, combustion processes in porous ceramic beds may be of a similar kind. However, at present high temperature heterogeneous catalysis is neither quantitative nor predictable. An overall lean combustion can also be achieved with locally rich regions ("Stratified Charge"). More traditionally, an efficient heat recirculation between products and reactants will also lower the flammability limit. However, this type of fluid dynamic process is closely related to turbulence, a classical unsolved problem in physical sciences. Although all practical combustion systems have turbulent flow, the essence of turbulence is still unknown. Advances in this field will help toward an understanding of emission formation, combustor performance (pressure loss) and possibly the conversion of chemical energy into turbulence.

Augmented combustion has been an academic curiosity for many years. By the use of electrical discharges which generate highly reactive radicals at crucial locations, high intensity combustion processes may be achieved. Electromagnetic radiation can be used to selectively excite molecules to higher energy levels, whereby the kinetic processes are influenced. In the hydrogen oxygen case, ultraviolet light has been used (23) to change ignition times, flammability limits, flame velocity etc. In principle, the radiation pulse is a non-thermal way of creating (by photodissociation) highly reactive radicals. Thus ignition and flame spreading may be achieved without the physical insertion of spark plugs or without imposing a temperature rise. For instance, it should also be possible to create an "ideal flameholder", characterized by a nonexistent pressure loss, and to use fuels in very lean mixtures. The ideal flameholder concept could be especially useful in the SCRAM-jet issue.

As the use of all liquid fuels involves a more or less heterogeneous combustion (even in the carburetted Otto engine), suitable modifications in the formation of a fuel spray and the subsequent combustion by using emulsified fuels with different physical and chemical characteristics relative to the basic fuel may improve combustion efficiency and reduce emission formation. For instance, with spray combustion an overall lean fuel-air mixture will attain locally high temperatures. This circumstance is most important for the formation of nitrogen oxides which, in the kinetically controlled regime, are very sensitive to locally occurring high temperatures. Spray combustion also leads to the formation of soot and particulates. The presence of water or another suitable liquid like methanol in the fuel droplets may cause a secondary disintegration and thus enhance the overall vapourization, mixing and ignition processes. Emulsified fuels will also have different transmission and fire safety characteristics.

Electrochemical developments, for instance with regard to rechargeable batteries, will impact on the competition between automotive propulsion units. The traditional automobile powered by an Otto engine transfers about 10 - 20 % of the available fuel work to the rear wheels. An electric car using a battery may reach efficiencies of more than 60 %. Assuming that the electricity is delivered from a central power plant with a total efficiency of 30 %, the electric car will be quite competitive from an energy utilization point of view. An extra bonus is the absence of combustion-generated emission in the users' area (cities). The main limiting factor to the introduction of battery powered cars has been and still is the low energy density of practical batteries. Technological developments that significantly increase the energy density will make the electric car a strong competitor to all other automobile systems.

The chemical to electric-energy conversion issue is related to progress in electrochemistry. Development of suitable fuel cells for automotive use could have a profound impact on transportation. Although present understanding of crucial processes in the fuel cell device is rather empirical, a technological breakthrough of heavy fuel cell applications (for instance power generation) could be achieved in the nineteen eighties.

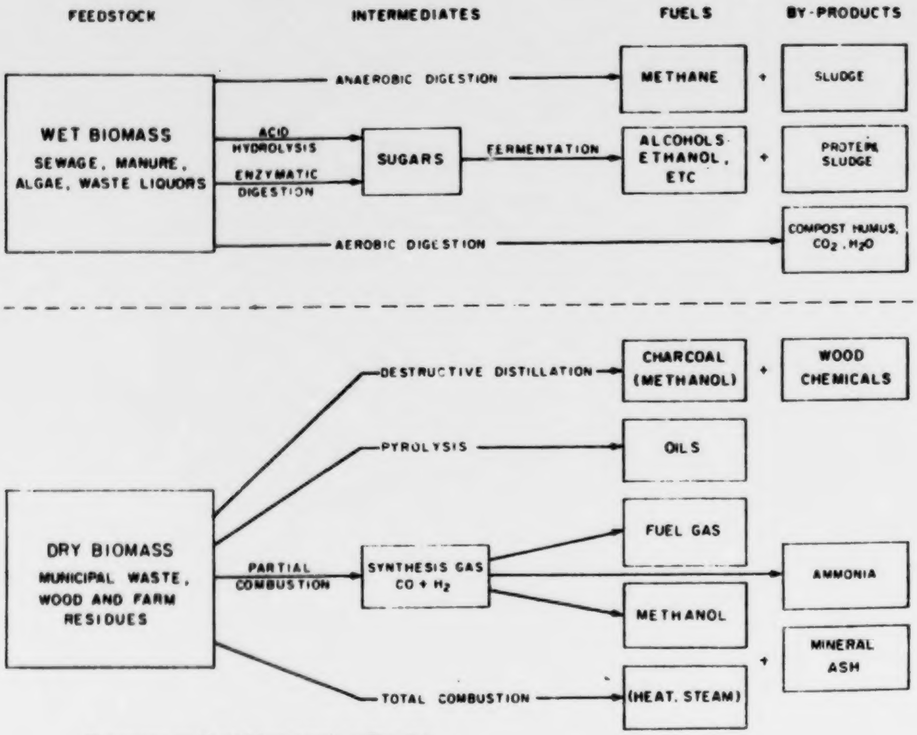
The irreversibility of chemical reactions (combustion) diminishes if they take place under conditions that approach equilibrium, but this has been difficult to realize in practical units. However, judging from the performance of biological systems, high efficiency in fuel oxidation processes might be achieved by the incorporation of several specially adapted intermediate reaction steps. It has been suggested (24) that a technically applicable solution could be to use inorganic metal oxides as intermediate steps, i.e. the fuel is oxidized by the metal oxide and the pure metal produced is reoxidized by air; the over-all process is an oxidation of the fuel with air (the chemical heat pump).

Nitrogen oxides are the villain with combustion in air. Apart from a possible fuel nitrogen content, these combustion-generated emission products could be entirely eliminated if pure oxygen were used instead of air for combustion processes. Usually, oxygen is produced by liquefaction and subsequent distillation of air. However, adsorption processes with different selectivities for different molecular species may produce on board oxygen by separation from air. Developments in this field are related to progress in surface and membrane sciences.

A gradual drift towards a "broad cut" fuel for transportation would probably be called for by the major oil companies as a first step in dealing with the dwindling petroleum resources. This fuel should have an octane number below 90 and a cetane number below 40 (25). Thus the quality from a traditional point of view would be rather poor. However, considering the total energy utilization aspect, it is advantageous to process a broad-cut fuel from raw petroleum.

Synthetic fuels (suitable for transportation use) and mainly of the hydrocarbon type have for a long time been produced from coal. Other future fuel alternatives, besides hydrogen, are methanol and electricity (for battery driven cars), produced from conventional primary energy sources in accordance with Figure 12-19. The growing interest in renewable energy sources may bring forth several new fuels suitable for transportation purposes. Solar energy stored as biomass is a likely primary energy source.

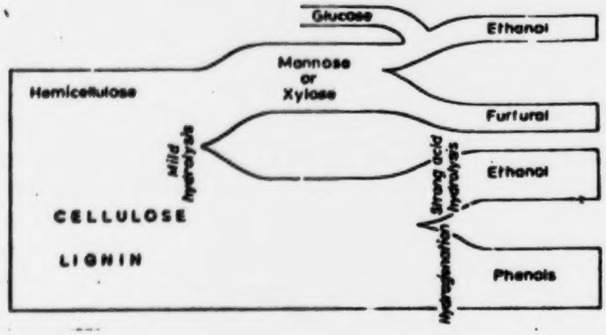
Some examples of different fuels obtainable from wet and dry biomass are given in Figure 12-20 (26). Wood, which is a typical example of biomass, may be the new material to replace crude oil. Figure 12-21 (27) shows some primary products processed from wood. Certain crops may also be processed to yield combustible substances (28). The hydrocarbon-like fuels may also be catalytically-thermally converted to a fuel gas containing hydrogen. One of the practical problems is the compatibility between fuel and other mechanical components in the propulsion system. Progress in polymer science, for instance as illustrated in Figure 12-22 from (29), should be taken into consideration when designing systems for alternative fuels.


FEEDSTOCK
INTERMEDIATES
FUELS
BY-PRODUCTS
WET BIOMASS
SEWAGE, MANURE, ALGAE, WASTE LIQUORS
ANAEROBIC DIGESTION
METHANE
+
SLUDGE
ACID HYDROLYSIS
ENZYMATIC DIGESTION
SUGARS
FERMENTATION
ALCOHOLS ETHANOL, ETC
+
PROTEIN SLUDGE
AEROBIC DIGESTION
COMPOST HUMUS, CO_2, H_2O
DESTRUCTIVE DISTILLATION
CHARCOAL (METHANOL)
+
WOOD CHEMICALS
PYROLYSIS
OILS
DRY BIOMASS
MUNICIPAL WASTE, WOOD AND FARM RESIDUES
PARTIAL COMBUSTION
SYNTHESIS GAS $CO + H_2$
FUEL GAS
AMMONIA
METHANOL
TOTAL COMBUSTION
(HEAT, STEAM)
+
MINERAL ASH

Biomass to Fuel Conversion Routes

Figure 12-20

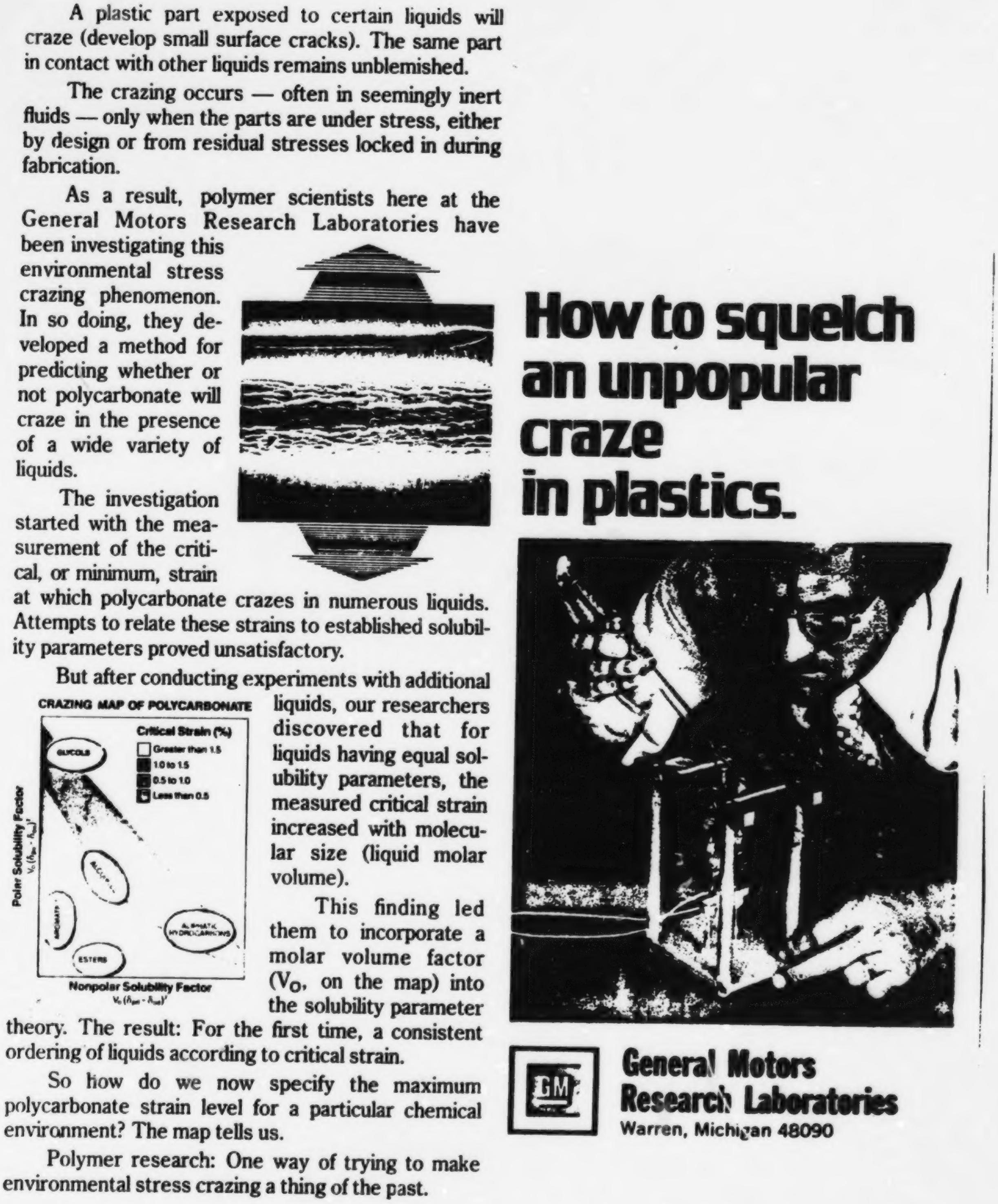
Biomass to fuel conversion routes (26).


Glucose
Ethanol
Mannose or Xylose
Hemicellulose
Furfural
Mild hydrolysis
Strong acid hydrolysis
Ethanol
CELLULOSE
LIGNIN
Hydrogenation
Phenols

Use of an integrated plant, producing all the components shown here could be the key to successful use of wood as a chemical feedstock that has been missing from past attempts

Figure 12-21

Products obtained from wood (27).



How to squelch an unpopular craze in plastics.

A plastic part exposed to certain liquids will craze (develop small surface cracks). The same part in contact with other liquids remains unblemished.

The crazing occurs — often in seemingly inert fluids — only when the parts are under stress, either by design or from residual stresses locked in during fabrication.

As a result, polymer scientists here at the General Motors Research Laboratories have been investigating this environmental stress crazing phenomenon. In so doing, they developed a method for predicting whether or not polycarbonate will craze in the presence of a wide variety of liquids.

The investigation started with the measurement of the critical, or minimum, strain at which polycarbonate crazes in numerous liquids. Attempts to relate these strains to established solubility parameters proved unsatisfactory.

But after conducting experiments with additional liquids, our researchers discovered that for liquids having equal solubility parameters, the measured critical strain increased with molecular size (liquid molar volume).

This finding led them to incorporate a molar volume factor (V_0, on the map) into the solubility parameter theory. The result: For the first time, a consistent ordering of liquids according to critical strain.

So how do we now specify the maximum polycarbonate strain level for a particular chemical environment? The map tells us.

Polymer research: One way of trying to make environmental stress crazing a thing of the past.

CRAZING MAP OF POLYCARBONATE
Critical Strain (%)
Greater than 1.5
1.0 to 1.5
0.5 to 1.0
Less than 0.5
GLYCOLS
ALCOHOLS
AROMATICS
ALIPHATIC HYDROCARBONS
ESTERS
Polar Solubility Factor
Nonpolar Solubility Factor

General Motors Research Laboratories
Warren, Michigan 48090

Figure 12-22

Polymer-related aspects of fuel systems.

There are some reasons why fuels produced from biomass could acquire increased importance in the future. Firstly, applications of the hybrid-DNA technique to plants may tailor them so that they yield fuels that are particularly suited for transportation purposes. Secondly, the combustion processes of today are very crude in comparison with the "combustion" in respiration systems. An understanding of this naturally occurring process will certainly improve all aspects of energy utilization. Already, certain modifications of photosynthesis processes have been suggested for hydrogen production.

As mentioned earlier, a broad-cut fuel will probably be supplied by the oil companies as a step towards better utilization of crude petroleum. This fuel is advantageously used in alternative heat engines (Brayton, Stirling and Rankine processes). IC reciprocating engines, for instance of the DISC-type (Direct Injected Stratified Charge), may also be adapted to this fuel. Moreover, the fuel may be converted to a hydrogen-rich gas in gas generators on board. If the Otto and Diesel engines of today are considered as belonging to the first generation of automotive engines, then the alternative heat engines may be termed the second and electrochemical converters of the fuel cell type the third generation.

Use of energy today within the transport sector is characterized by low efficiencies, mainly because today's heat engines have low efficiencies at part-loads. However, part-load driving patterns are ideally suited for fuel-cell propulsion as the efficiency of these increases with diminishing loads. Moreover, the absolute efficiency values are substantially higher. Hydrogen is a first-choice fuel for fuel cells. If hydrogen fuel cells are to become the "ultimate" transportation propulsion system in a sufficiently long time perspective, the question is whether the traditional Otto and Diesel engines will be used in the meantime or if alternative heat engines will be introduced. From a technical point of view, the EC (External Combustion) process, with combustion gases separated from the thermodynamic cycle medium, is ideally suited to benefit from progress in combustion science. This also applies in principle for gas turbine combustion at constant pressures. However, from an economic and utilization point of view, an introduction of alternative heat engines requires changes in established infrastructure networks and would thus be costly and protracted. This is illustrated schematically in Figure 12-23 from (30).

12.5.1 Methanol fuelled IC Engines

Apart from being a long-term competitor, methanol is also a short-term precursor to hydrogen. At present methanol is mainly processed from fossil sources, but in the future it may be manufactured from alternative primary energy sources. By contrast with the hydrogen case, methanol may to a large extent benefit from the existing infrastructure network for fuel distribution. Moreover, methanol and ethanol are historically well-known alternative engine fuels and were used as such during previous periods of restricted petroleum availability.

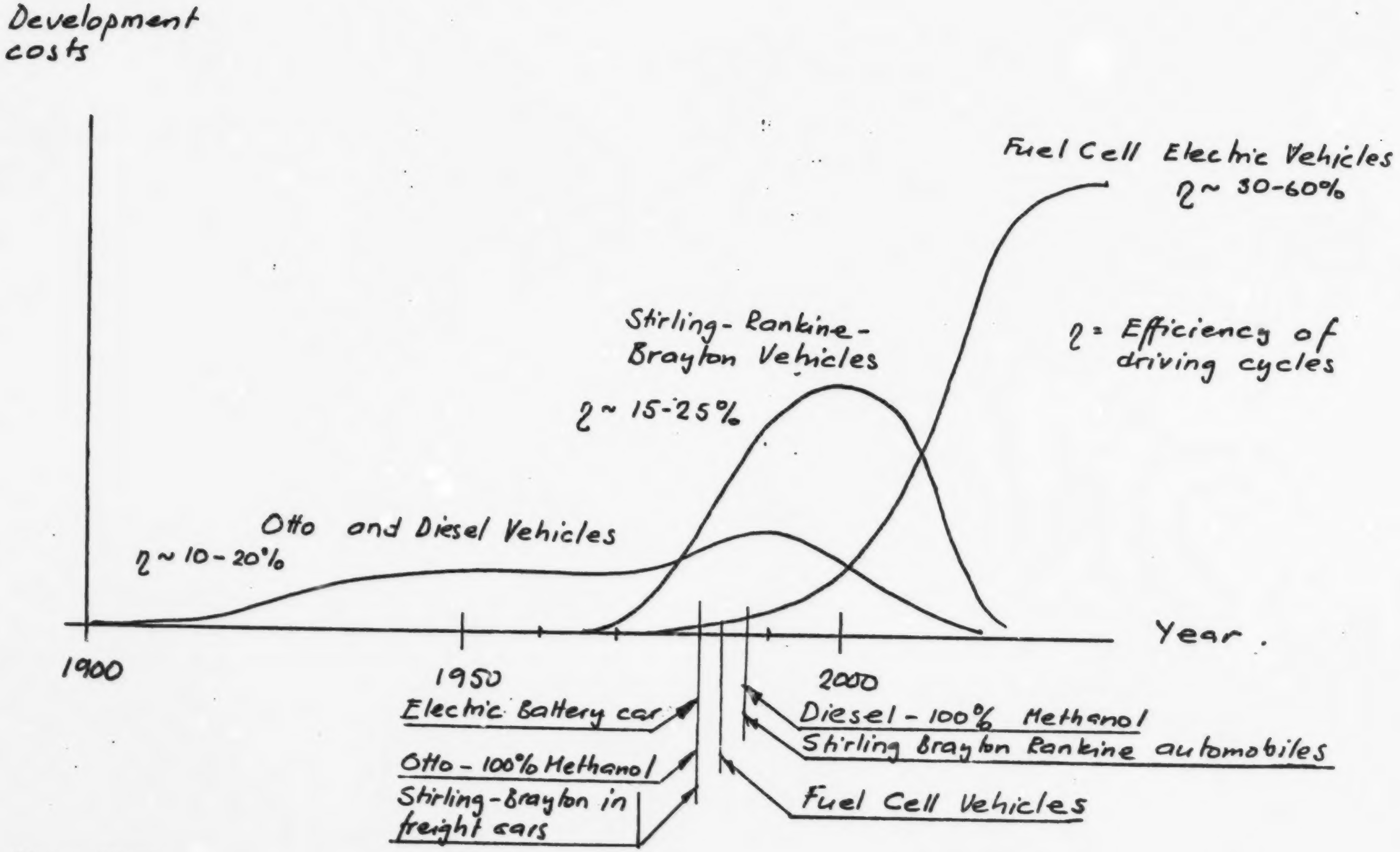


Figure 12-23

Development costs for different power systems (30).

Not only IC reprocicating engines, but also alternative heat engines and fuel cells may use methanol as a fuel, In general, experience has shown that the following applies when methanol is used in IC engines instead of traditional hydrocarbon fuels:

Vehicle

- At equal range about double the tank volume is required.
- Methanol-resistant components are required in the fuel system.
- The carburettor and fuel injection systems must be adapted to larger flows.
- The intake system may have to be preheated.
- Cold-starting devices may be necessary.

Engine performance

- Higher inducted mass provides higher power.
- Efficiency is improved because of cooling during compression.
- Higher compression ratios may be employed because of high octane characteristics of methanol.
- Less soot formation but poorer autoignition characteristics in Diesel engines.

Environmental aspects

- Important reductions in emission components such as lead, sulphur compounds, higher hydrocarbons of the polyaromatic type and soot.
- Aldehyde emission may increase.
- Toxicological impact of methanol use on the environment is unknown.

Details of the performance of pure methanol and of methanol-petrol mixtures in various engine modifications can be found for example in (4).

A methanol fuel concept which resembles the hydrogen case concerns on-board generation of fuel gas. This could be termed a successful hybrid technique as regards fuel technology, since the beneficial properties of the basic fuels are retained while unsuitable characteristics are dispensed with. The gas generator concept can also be applied to C_xH_y hydrocarbons, but methanol is a more suitable substance for the thermal and catalytic disintegration processes within the gas generator. Briefly, the splitting of methanol takes place according to the following reactions (engine reject heat may be used)

$$CH_3OH \rightarrow 2H_2 + CO$$

or, with water added

$$CH_3OH + H_2O \rightarrow 3H_2 + CO_2$$

Other reactions are also possible. Thus, the fuel gases consist of H_2, CO, CO_2 and H_2O vapour.

The high hydrogen content in the generator outlet mixture will generally have the same advantages with regards to performance and emission as were mentioned earlier for the hydrogen engine. Furthermore, existing infrastructure networks for fuel distribution can be maintained. Practical problems to be overcome concern the performance of a non-stationary engine and cold starting characteristics.

Some methanol-related activities are already in progress in Sweden. After the "oil crisis" of 73/74 a special company, Metanolbolaget, was formed to study production methods and applications within the transport sector. The main reason for our increasing interest in methanol as a fuel is to achieve preparedness and self-sufficiency in situations when petroleum might become scarce. Traditionally in Sweden, such situations have hitherto been met by relying on producer gas from wood, which is acceptable in Otto engines but unsuitable for modern turbo-charged Diesel engines. In order to enforce the preparedness issue, some production must exist even during normal times. However, in this case a corresponding consumption must be arranged. One way of solving this problem is to use an 80/20 % petrol-methanol mixture as the general fuel for all Otto engines. This would correspond to an annual consumption of about 1 Gkg of methanol, as compared to the current import of 120 Mkg, mainly for chemical purposes.

Practical tests have been performed on a number of vehicles with the 80/20 % mixture. Otto engines fuelled with pure methanol are also being developed. Dual fuel Diesel engines are also being studied. As methanol posesses rather poor self-ignition characteristics, the Diesel process may require a small quantity of "primer" fuel for reliable ignition.

For the immediate future (1978 - 1981), the following main fields of activity are being discussed (31): Feasibility and production studies, engine applications, fuel distribution and systems analysis. For the time being, most of the general engine-related problems of methanol use have been solved. In a longer time perspective (32), it is planned to extend the activities of Metanolbolaget to cover all alternative engine fuels and also distribution and production issues. During the next 5 - 10 years, all methanol demand will be supplied by imports. Projects are being studied for the large-scale domestic production of methanol from wood, turf, coal and sulphur-rich oil residues.

12.5.2 Electric vehicles

Historically, electric cars are fairly well-known. Already at the end of the 19th century, various vehicles were powered by lead-acid, nickel-iron and nickel-cadmium batteries. Ranges of 300 km before recharging with a speed of 10 - 15 km/h were obtained. However, rapid developments of the petrol engine, for instance concerning the starting process and manufacturing technology, made the Otto automobile preferable to electric and steam powered cars.

The total number of electric cars is today around one million. Most of these are used for goods transport inside industries, and the remainder are mainly used for leisure time activities.

The main obstacle with electric cars is the poor energy density of the batteries. Figure 12-24 from (33) gives some examples. The energy requirement for urban drive cycles is usually around 0.5 J/m kg. Assuming a battery weight fraction of 0.3 in the vehicle and a battery energy density of ε J/kg, the range R will become:

$$R \cong 0.6 \cdot \varepsilon \ [m]$$

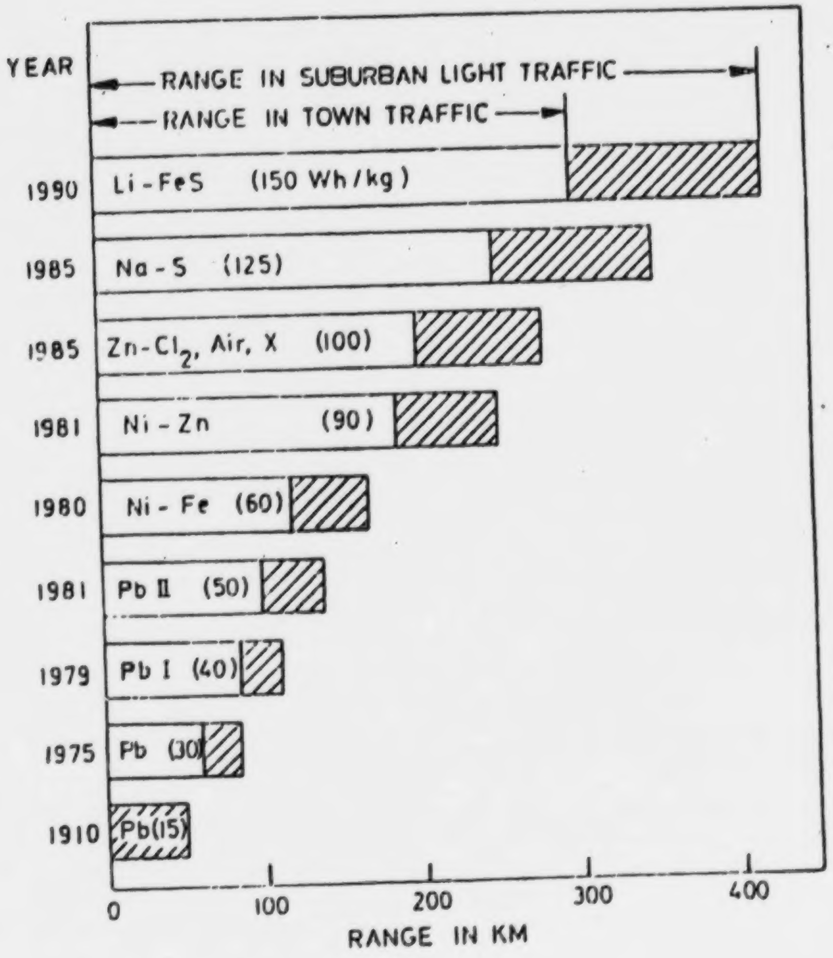


Figure 12-24

High energy electric vehicle batteries. Forecast of energy densities and possible driving ranges (33).

Swedish developments in this field, notably by AGA Innovation, SUAB, Nife-Jungner and some university institutions, have resulted in iron-air, nickel-iron and nickel-zinc batteries. The first generation of iron-air batteries was run for 50 cycles with an energy density of around 300 kJ/kg. The iron electrode then developed was later combined with a nickel electrode in the SUAB (Svenska Utvecklingsbolaget) nickel-iron battery with an energy density around 200 kJ/kg. A nickel-zinc battery ("Vibro-cell") developed by AGA-TUDOR has an energy density around 300 kJ/kg. All these batteries can provide ranges between 120 - 200 km, which might be a limiting performance requirement for the first generation of electric car purchasers. These will probably use the electric car as a second family vehicle, which is mainly used in rather short intraregional trips.

A substantial amount of Swedish battery research is supported by government funds. Apart from the projects mentioned above, research work is also performed at university institutions, for instance on a second generation of iron-air batteries with a possible energy density of 600 kJ/kg, and a low cost alkaline lead battery system with an energy density of about 180 kJ/kg (34).

Final battery costs are of course very dependent on whether mass production can be achieved. It has been estimated (34) that in the near future the cost could be around 150 - 300 cr/kJ. The alkaline lead battery would cost around 60 cr/kJ and a second generation of the iron-air battery around 30 - 60 cr/kJ.

In order to prepare for an introduction of electric vehicles, experimental or demonstration units should be introduced at an early stage in order to gain experience of the adaptability of the electric car to ordinary traffic patterns, as well as of managing and servicing at the consumer level. The Swedish Telecommunications Services have ordered 14 electric vehicles from a newly started Swedish company, SETU (Svenska Elektrotransport Utveckling AB) (35). The electric vehicles will be built from proven components, using a Mercedes minibus chassi type 307-307 which is adapted to electric propulsion. The useful load is 700 kg, the range 80 km per charging and the maximum speed 80 km/h. The batteries are of the conventional lead-acid type. These vehicles are to be used in connection with service and maintenance work on telephone networks.

Electrically propelled buses for intraregional transportation constitute an environmentally competitive alternative to the IC engine bus. In Stockholm, electric buses will be used on certain inner-city routes in a few years' time. Fleet vehicles are generally well suited for battery operations since recharging or possibly battery changing can conveniently be carried out at central depots. However, a battery-hybrid design could also be advantageous; here the batteries are recharged on board by an electric generator powered by a heat engine with a suitable fuel. The heat engine is tailored to give minimum emisssions. In this way, the limited capacity of present-day batteries is circumvented.

Another way of dealing with limited battery capacities is to provide a network of "quick-change" stations corresponding to the current petrol stations. An advanced concept (36) is to draw electrical energy from a conductor installed in the roadway. The energy is transferred magnetically, and no physical contact exists between the vehicle and power source, Figure 12-25.

The addition of a flywheel system to electric vehicles may improve overall performance. The flywheel is used for power-peaks, thus increasing battery life. Moreover, flywheels could make use of regenerative braking.

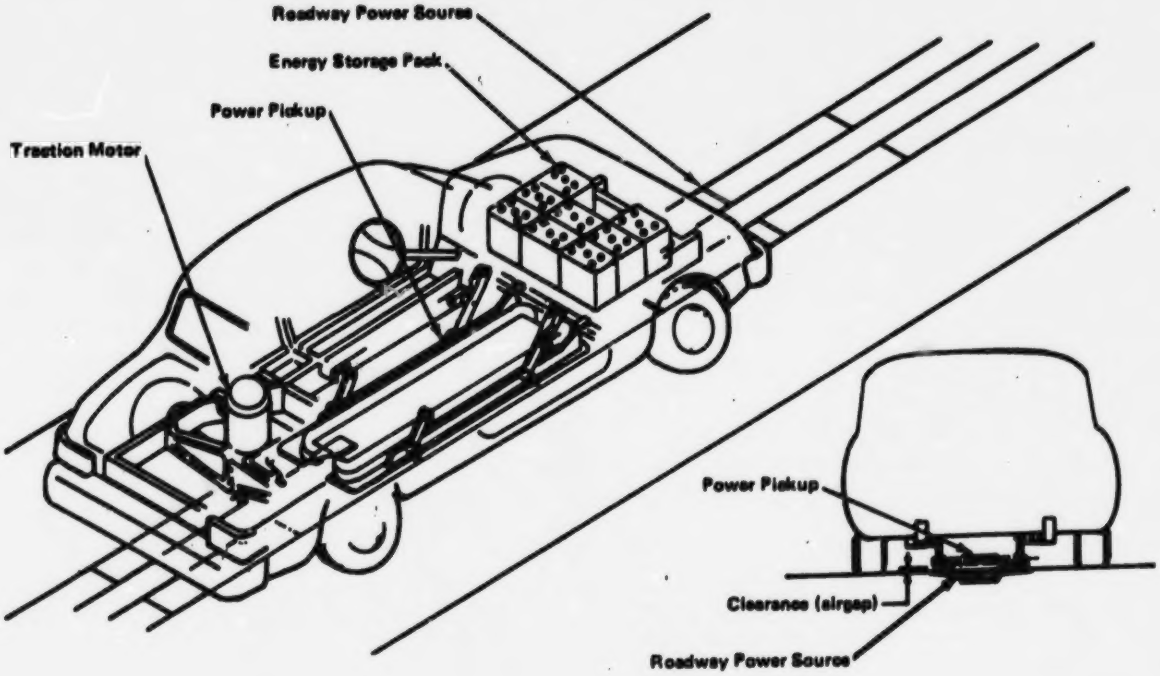


Figure 12-25

Roadway power system for electric vehicles (36).

Combustion generated emission components are absent for electric cars, apart from a possible small amount of ozone. If the electric energy used for battery charging is generated in a combustion-driven power plant the emissions are concentrated to this location. Another pollutant, engine lubricating oil, is also absent. Ordinarily, about 50 % of this oil is consumed in the engine, while the other part is dissipated through leakage, waste etc.

Developments within the field of fuel cell technology started to make significant advances in the fifties when porous metal electrodes were produced. In the sixties, the needs of the space programs initiated intense activities within the fuel cell field. Often empirical approaches were used, for instance regarding catalyst development, and many systems were developed by the trial and error method. When the space programs declined in the seventies so did the fuel cell technology. With the present growing interest in efficient energy conversions, a new wave of fuel cell developments may start, particularly as regards stationary power plant applications. Mobile applications can also benefit from these activities. Efforts should be devoted to increasing our understanding of basic electrode processes, including catalyst actions. New engineering approaches and design optimizations should also be studied.

Fuel cell powered automobiles are actually electric-hybrid vehicles, since ordinary batteries are usually incorporated in the system. Compared to battery powered cars, the range performance is greatly extended. A suitable liquid or gaseous fuel is used in the fuel cell to generate electricity for charging the battery. The battery can be quite small and is used for peak-power demands. The fuel cell supplies power for level-road cruising and power acceleration, accessories etc. When the car is operated at less than maximum power, which occurs during most intraregional driving, the battery is undergoing recharge. Obviously, developments will be required to find out the optimum mixture of fuel cell power and battery power. Driver habits and preferences are important boundary conditions in this respect.

12.6 Factors influencing future energy requirements within the transportation sector

The main problem of this market study is to forecast future energy requirements. Particularly after the year 2000, there is no solid basis for extrapolation available. However, in the economic scenario, Chapter 3, the following assumptions are specified regarding the energy demands of the transportation sector:

Table 12-6

Specified transportation energy demands.

Year	1978	2025			1978 - 2025
	Energy (PJ)	Nominal increase	Specific energy improvement	Energy (PJ)	Annual increase
	270	+ 125 %	- 40 %	390	0.73 %

Both the postulated nominal energy demand and the specific energy improvement (which together give the net energy requirements) are uncertain. As the net increase is composed of the nominal increase and the specific energy improvement, obviously innumerable mathematical combinations of these quantities may give the same figure for the net increase. However, the total economy may be completely dependent on the specific ways of reaching this net effect. Some factors which influence these quantities are therefore discussed below.

Prescribed energy savings will often put increased pressure on organization processes within society. For instance, mass transit bus systems require flexible working hours and vacation periods for optimal potential. In addition, well developed networks for these transportation modes are required, especially as regards terminals for people and goods. This in turn demands among other things sufficient space, and thus far sighted planning within society as a whole.

It is often assumed that a decrease in the demand for transportation energy can be achieved in the general context of the evolution of a society. Thus it could be worthwhile to identify some trends in current developments which may counteract the drive towards a decreased energy consumption. For instance, there is a policy of dispersing ("decentralizing") people and institutions away from congested cities. However, the individuals involved often have their work and service establishments still in population centres. An important question is therefore what such decentralization will actually cost in terms of future transportation energy. In addition, flexibility of working hours and vacation periods and more part-time work will encourage women to participate in professional work. Coupled with decentralized living, this will probably make a two-car system within the family a necessity. Moreover, the relative number of elderly people is expected to increase with time. This is due to the low birthrate and the extended lifespan. In Sweden today, there are 2.2 working people for each pensioner (38). The pensioner group forms already now a strong pressure group with special and deviating preferences as regards transportation time, comfort etc.

Usually the transportation energy demands refer to energy consumed during the transportation act as such. However, in a complete energy analysis consideration must also be given to energy used in the production and maintenance of vehicles, roads and terminals (including requirements of light and heat). Energy consumed in taking care of traffic victims should also be incorporated.

New investments in transportation will usually have different total energy consequences for different transport modes as regards the total number of passengers or ton-km. For instance, increased surface shipping may require extended channel systems, new harbours etc. Increased land transport may require a further development of the infrastructure along the roads, whereas increased air transport may require an extended terminal system.

Specific energy improvements within the transportation sector are closely related to the technical characteristics of the vehicles. Apart from a low fuel consumption, new investments in transport vehicles are also determined by factors such as low emission, multi-fuel features, safety etc. Studies are being performed on alternative propulsion systems founded on the Stirling, Rankine and Brayton cycles. These are characterized by combustion at a constant pressure. This makes the combustion process more easily controllable (compared to IC engines), and thus an optimization of fuel consumption, emissions and multi-fuel features may be achieved. However, any introduction of alternative propulsion systems that deviate largely from present IC systems must be followed by a substantial economic back-up, consisting of R & D, preparation for mass production, an international component industry, service, maintenance etc.

In a far-sighted perspective the inherent limitations of energy conversion in heat engines could be overcome by electrochemical systems (fuel cells plus electromotors). As the private car in an urban environment uses by far the largest quantity of transportation fuel, any future propulsion system should demonstrate a substantial improvement of part-load efficiency compared to IC engines in order to contribute to transportation fuel savings. In the long run, electrochemical converters will probably become the preferred choice for propulsion systems. Synthetic fuels such as hydrogen and methanol are ideally suited for fuel cells, but they may also be used in suitable converted IC engines until these are replaced by electrochemical systems.

The effort to reduce transportation energy demands may also result in the development of quite different transport systems, by comparison with those in use today. For instance, pneumatic transport of goods could be an attractive alternative to transport by lorry. The advantages of pneumatic systems are low costs for use and maintenance, low labour requirements, low emission and functional safety.

LTA transport could offer some alternatives to both air and surface transport, especially for heavy lifts and in cross-country work. Futuristically, the propulsion system could be based on solar cells and electric motors.

The easiest way to save transportation fuel is to refrain from travelling. Telecommunications could be used in order to deliver a message or participate in a meeting. The development of an infrastructure of acoustical and visual terminals for message exchange could reduce the impact on transportation energy of any physical and geographical developments in society as regards the location of dwellings, working places, service institutions etc.

12.7 Energy consumption in the transportation sector

The introduction of hydrogen fuelled transportation requires profound changes in the fuel distribution network, vehicle construction and the general convenience of the consumer. Once the energy consumption of different transportation modes in different transport missions has been identified, it may be possible to make a list of priorities showing in which fields the efforts should be concentrated. Further, technical requirements for the corresponding future vehicles may be specified.

Tables 12-7 and 12-8 summarize the Swedish energy consumption for passenger and goods transportation in different operating modes. Including the consumption for international refuelling, military transport, vehicles in construction etc, the total amount was 272 PJ in 1973.

Table 12-7

Swedish energy consumption structure for passenger transportation in 1973 (39).

		Subdivision (PJ)		Energy efficiency
	Total (PJ)	Intra-regional < 100 km	Inter-regional > 100 km	MJ per passenger-km
Car	115	92.2	22.8	1.3 - 2.6
Bus	6.5	6.1	0.4	0.35 - 0.85
Rail	3.6 (electric)	1.1	2.5	0.55
Aero	3.6	-	3.6	4.3
Ship	3.6	3.4	0.2	5.4
Total (PJ)	132.3	102.8	29.5	

Table 12-8

Swedish energy consumption structure of goods transportation in 1973 (39).

	Total (PJ)	Subdivision (PJ)		Energy efficiency
		Intra-regional < 100 km	Inter-regional > 100 km	MJ per ton km
Road	42.5	21.2	21.3	1.4 - 2.7
Rail	3.6	0.07	3.53	0.22
Ship	3.6	0.11	3.49	0.72
Total (PJ)	49.7	21.4	28.3	

Obviously, the heavy consumers of transport energy are cars in intraregional use and, to a somewhat smaller extent, cars in interregional use and lorries in intraregional and interregional use. If the same qualitative consumption profile is also assumed to exist in the future, then these transportation modes should also receive most attention in the present market analysis.

The fuel economy of the private car is presently mainly determined by the efficiency of the automobile propulsion system at low part-loads. Average efficiencies are in the range of 5 - 15 % (40). However, from an energy utilization point of view, the driving pattern seems to be better suited for fuel cell electrical propulsion systems, so that some development and introduction of these systems is included in the estimation below of future transportation energy requirements. Furthermore, as hydrogen and methanol are preferred fuels for fuel cell systems, the mere introduction of these fuels in transportation will constitute a strong incentive to develop fuel cell propulsion systems.

As was stated above, a large fraction (~ 30 %) of Swedish transport energy is consumed by a very heterogenous group of vehicles with varying requirements for fuels and propulsion units. Military vehicles, for instance, put survival characteristics above civilian characteristics such as emission and fuel consumption. International transport in Sweden must be able to receive the proper fuel. These transport modes require large stored reserves and will probably be the last ones to convert to a new fuel system.

12.8 Estimation of future quantities and proportions of different vehicle categories and energy carriers

According to the general scenario of this study, the useful transport work will increase by the following factors:

Year:	1975	1985	2005	2025
Factor:	1.0	1.18	1.63	2.25

This corresponds to a 1.6 % annual increase. Knowing the transportation work structure in 1975, Table 12-9 can be calculated.

Table 12-9

Useful transportation work (person-km and ton-km) vs time. (The data for 1975 are estimated from (39) and (41)).

Year →	1975	1985	2004	2025
Passenger transport (G person-km)				
Auto	62.0	73.5	95.5	111.0
Bus	8.5	9.0	16.5	33.0
Rail	6.5	7.5	10.0	19.5
Other	1.0	2.0	5.0	12.5
Σ 10^9 person-km	78.0	92.0	127.0	176.0
Goods transport (G ton-km)				
Freight vehicles	23.0	27.0	38.0	52.0
Rail	18.0	22.0	30.0	41.0
Ships and other	8.0	9.0	12.0	17.0
Σ 10^9 ton-km	49.0	58.0	80.0	110.0

The useful work produced, G, is defined as

$$G = n \cdot s \cdot l \qquad \text{(Equation 1)}$$

where:

n = number of vehicles

s = average distance travelled per year

l = load factor

It is assumed that the load factor increases with time. For instance, the present average number of persons per car, 1.6, is assumed to increase to 1.8 in 1985 and to be constant thereafter. It is also assumed that vehicles will have a constant average annual travelling distance throughout the period. This distance is about 14000 km for the car, about 32000 km for the heavy freight lorry and about 38000 km for the bus.

With the aid of figures given in Table 12-9 and applying Equation 1 with adjustments from (41), the numbers of vehicles which will carry out the required useful transport work were calculated. The results are given in Table 12-10.

Considering now the time scale for the introduction of new fuels, the impact on the total energy demand for transport is determined by:

- The time required for developing the modified vehicle system.
- The buyers' preferences, which determine the fraction of modified vehicles within the total inflow of new vehicles.
- Scrapping, which determines the total inflow of new vehicles.

Presently the total number of cars in Sweden amounts to about 270000. During the seventies the annual inflow of new cars has averagely been about 7 - 8 % of the total. It is assumed that, in order to lessen the burden on society, conventional IC engines will be used as far as possible provided that they can be modified for use with synthetic fuels. If a decision is made in the early eighties to proceed towards new fuels, the first vehicles may possibly appear in the early nineties.

The issue of battery vehicles has also been discussed previously. The prospects for this transportation mode are closely related to battery developments. The introduction of these vehicles has a strong environmental back-up; it is therefore assumed that quite a large fraction of the intraregional transportation in 2025 will be covered by such vehicles. The introduction will begin around 1990 and will keep pace with battery developments.

Table 12-10

Assumed total numbers of vehicles vs year.

Year and number → Vehicles ↓	1975		1985		2005		2025	
	Number	Rel. load factor	Number	Rel.load factor	Number	Rel.load factor	Number	Rel.load factor
Cars	$2.7\cdot10^6$	1.0	$3.0\cdot10^6$	1.125	$3.8\cdot10^6$	1.125	$4.4\cdot10^6$	1.125
Buses	$1.4\cdot10^4$	1.0	$1.58\cdot10^4$	1.0	$2.06\cdot10^4$	1.4	$3.2\cdot10^4$	1.8
Freight vehicles (total)	$1.56\cdot10^5$		$1.8\cdot10^5$		$2.2\cdot10^5$		$2.5\cdot10^5$	
Small freight cars (petrol)	$0.7\cdot10^5$		$0.6\cdot10^5$		$0.4\cdot10^5$		$0.2\cdot10^5$	
Large freight vehicles	$0.86\cdot10^5$	1.0	$1.2\cdot10^5$	1.0	$1.8\cdot10^5$	1.17	$2.3\cdot10^5$	1.4

Note 1: Small freight cars (petrol fuel 1975) consume less than 20 % of the fuel consumed by large freight vehicles.

Note 2: Average travel distance per year for all years:

Car	14000 km
Bus	38000 km
Freight vehicle (large)	32000 km

Note 3: The relative load factor is referred to 1975. For instance that year every car carried on average 1.6 persons. Thus, in 1985 the number would be 1.6 · 1.125 = 1.8 etc.

In accordance with the assumptions given for this study, it is presumed that petroleum imports will reach a maximum in 1990, will decrease slowly up to 2005 and then more rapidly to become almost zero in 2025. This implies that the change from fuels based on natural petroleum must start sufficiently early, in order not to be too disruptive in the twenty-twenties. Thus in all scenarios, changeover from petroleum fuel is assumed to start slowly in about 1990 with the introduction of IC engines modified for use with alternative fuels and/or electrical vehicles. In this way the IC engines may be used beyond the year 2020. It is also assumed in the appropriate scenarios that fuel cell vehicles will be ready for marketing during the final years of this century.

Within the framework of the given directives, the following alternatives in scenarios A, B and C are regarded as most plausible and will be discussed. Petrol and Diesel oil (C_xH_y) remain the principal fuel throughout the period in all alternatives. They may be natural or synthetic or mixtures thereof.

Scenario A

Alt. 1 Intensive introduction of battery electric vehicles (max 30 % in year 2025).

Alt. 2 Intensive introduction of hydrogen fuelled vehicles and low intensity introduction of battery electric vehicles.

Scenario B

Alt. 1 Intensive introduction of methanol fuelled vehicles and low intensity introduction of battery electric vehicles.

Alt. 2 Intensive introduction of methanol fuelled vehicles, no battery vehicles.

Scenario C

Alt. 1 Low intensity introduction of battery electric vehicles. Note: This may correspond to a reference situation representing a "spontaneous" development from the technology of today.

Alt. 2 Low intensity introduction of both hydrogen fuelled vehicles and battery electric vehicles.

The corresponding assumed development of the vehicle mixture vs time is illustrated in Figures 12-26, 12-27 and 12-28.

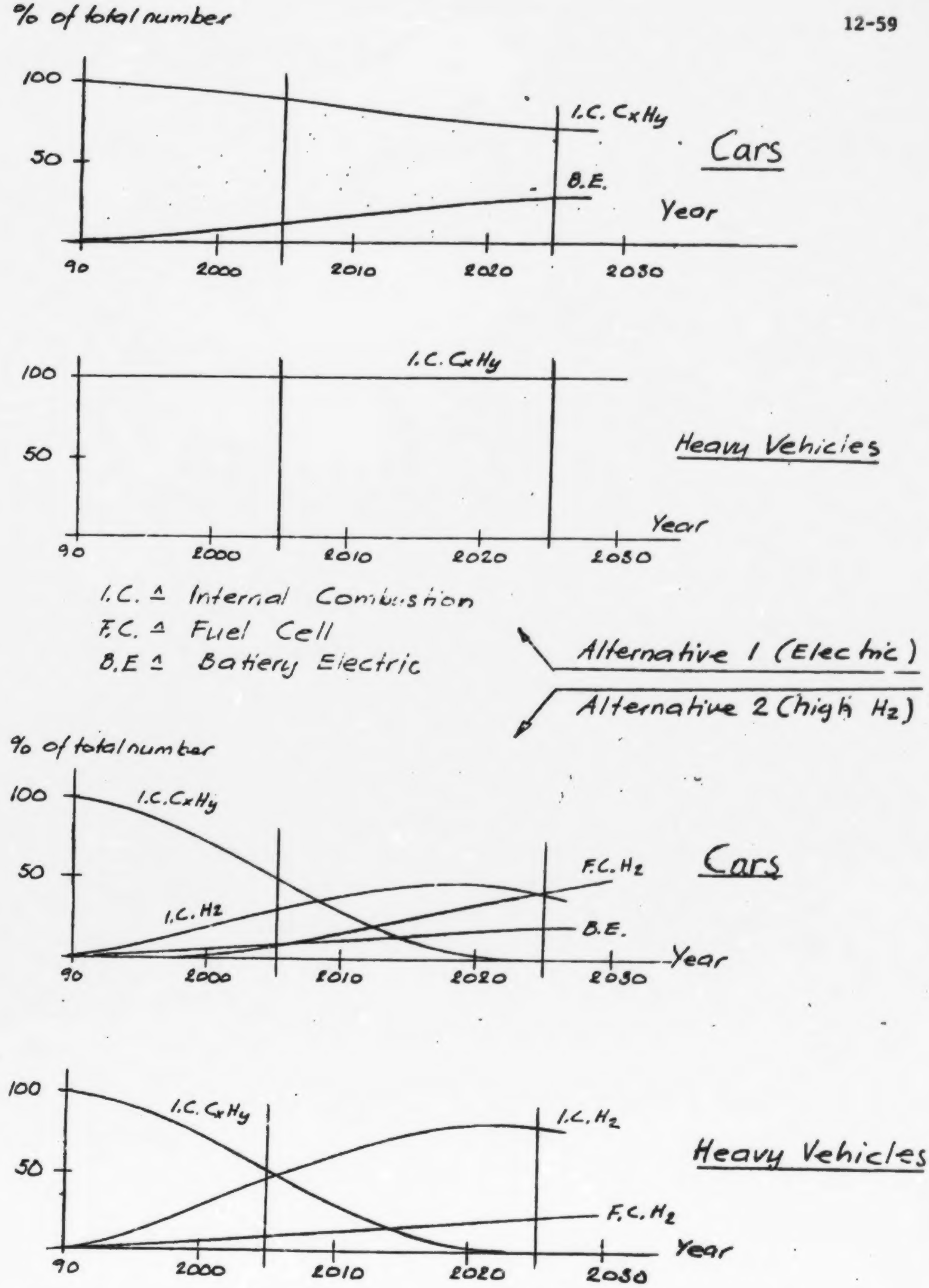
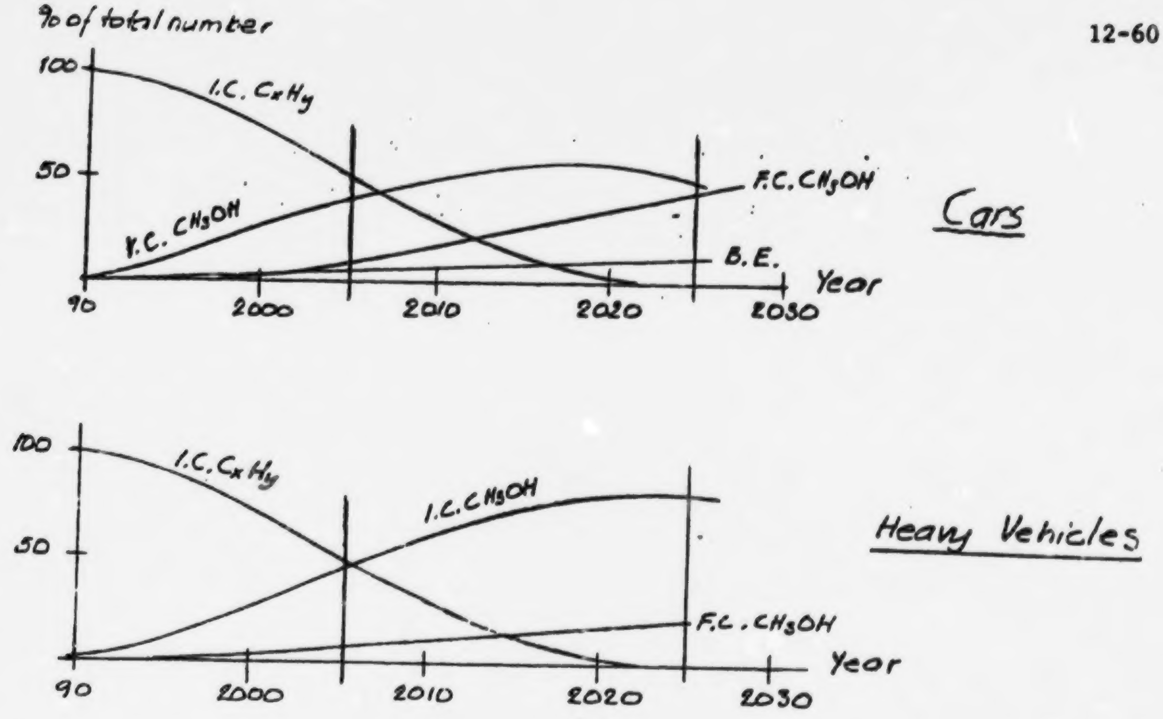


Figure 12-26

Assumed development of vehicle mixture. Scenario A (Nuclear).



I.C. ≙ Internal Combustion
F.C. ≙ Fuel Cell
B.E. ≙ Battery Electric

Alternative 1 (Methanol batteryelectric)

Alternative 2 (Methanol only)

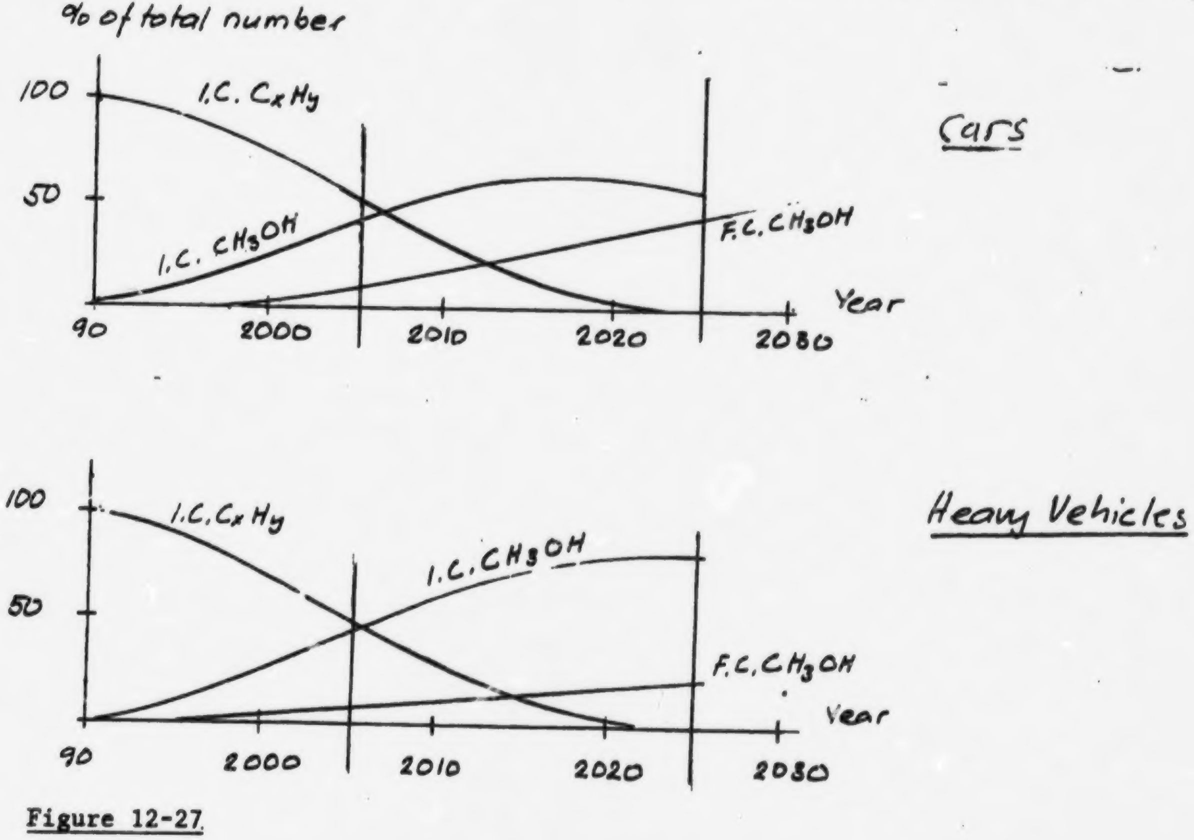
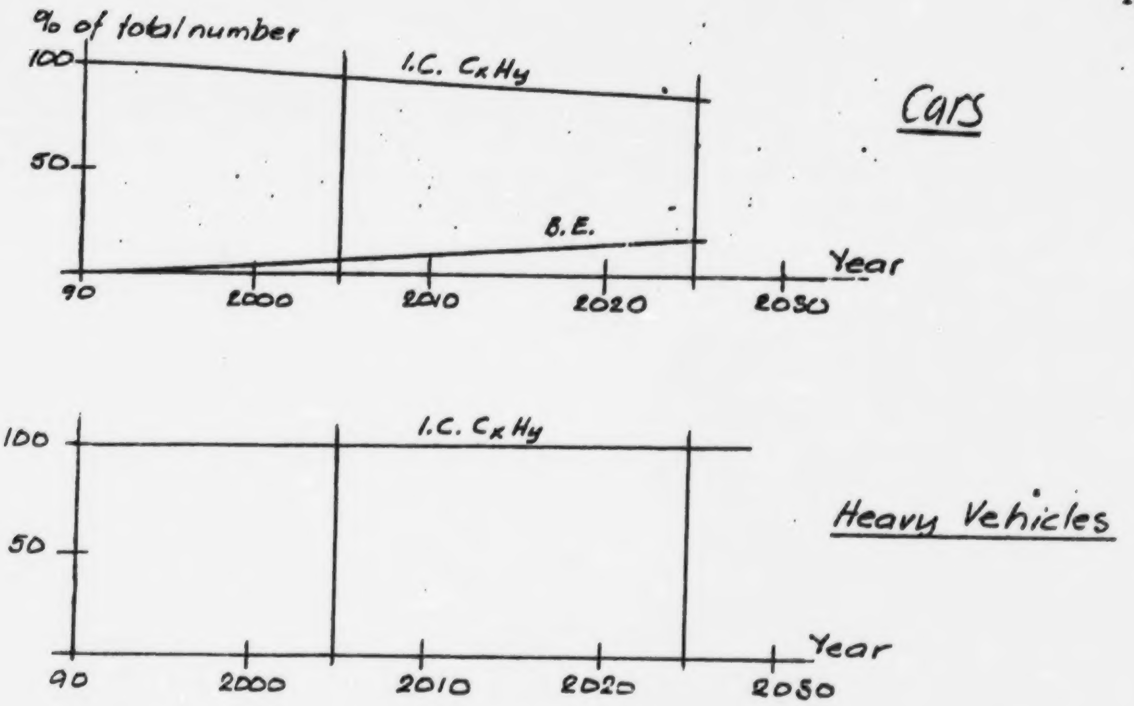


Figure 12-27

Assumed development of vehicle mixture. Scenario B (Biomass).



I.C. ≙ Internal Combustion
F.C. ≙ Fuel Cell
B.E. ≙ Battery Electric

Alternative 1 ("Spontaneou

Alternative 2 (low H_2)

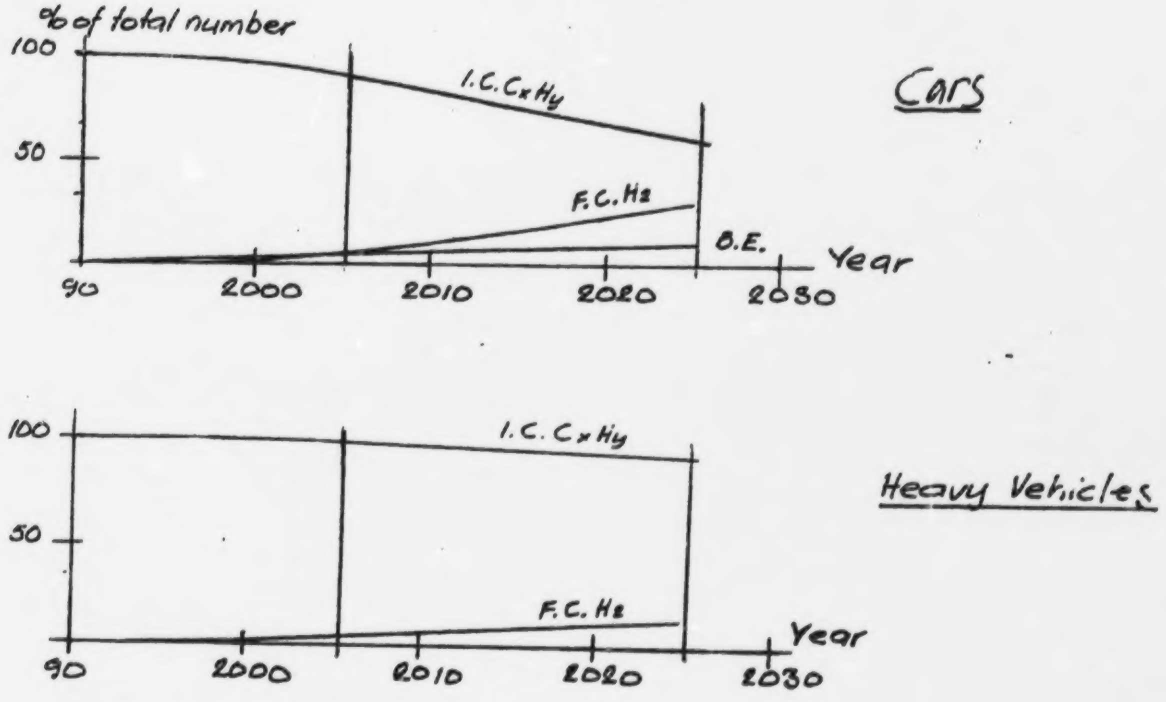


Figure 12-28

Assumed development of vehicle mixture. Scenario C (NG and synthetic).

Turning then to the specific energy consumption characteristics, the following definitions are used

m = vehicle mass

μ = equivalent motion resistance coefficient

g = 9.81 (m/s^2)

η = power train efficiency (fuel → rear wheels)

e' = specific energy consumption (J/m)

The energy required (on board energy storage) in joules to propel the vehicle one meter is given by:

$$e' = \frac{m\mu g}{\eta} \quad (J/m) \qquad \text{(Equation 2)}$$

The usefullness of this expression lies in the separation of the specific energy consumption into parameters subjected to technical development (mass, motion resistance and efficiency); each of these may be assigned a technological change with time. Equation 2 is justified because the equivalent motion resistance coefficient seems to be relatively independent of the driving cycle. Quantitatively, it has a value around 0.04 today (40).

The total energy requirement Q is then given by:

$$Q = e \cdot n \cdot s \quad (J) \qquad \text{(Equation 3)}$$

where:

e = average specific energy consumption (J/m)

Tables 12-11 and 12-12 give estimated values of vehicle mass, motion resistance and efficiency, based on assumptions of reasonable technical developments. Utilizing these figures plus the assumed product mixture, the average specific fuel consumption, the total number of vehicles and the distance travelled by vehicles, the corresponding annual energy carrier consumption is calculated for the years 2005 and 2025 with the aid of the equations given earlier.

If the energy demand is split up according to the different transport tasks, the situation in 1975 was:

Passenger transport	135 PJ;	50 %
Freight transport	54 PJ;	20 %
Other transport	81 PJ;	30 %

"Other transport" refers to a very diversified group which includes the armed forces, international shipping, air traffic, engine-powered machines, leisure time boating, etc. It is not clear how the fuel consumption of "other transport" will develop with time. However, it seems reasonable to assume that this group will be rather strongly associated with liquid hydrocarbons, although alternative fuels may be in use in the passenger and freight transportation sectors. As regards the energy requirements of "other transports", the values for 2005 for scenarios A, B and C have been taken from the "low alternative" in (39) for the "nuclear", "biomass" and "oil" scenarios, respectively. The same values are used for the year 2025, on the assumption that although the work volume will increase this will be balanced by a corresponding specific improvement in technical organisation. As regards the fuel used, it is assumed that only in the alternatives "high intensity hydrogen introduction" and "high intensity methanol introduction" will appreciable amounts of these alternative fuels penetrate into the "other transport" domain.

Tables 12-13 to 12-16 show the total energy carrier requirements.

Table 12-13

Energy carrier consumption for the years 1975 and 1985
Same for all scenarios.

Transport mode	Energy carriers (PJ)					
	C_xH_y	CH_3OH	H_2	Electr.	Σ	
Passenger	131			3.5	134.5	Year 1975
Freight	44			3.5	47.5	
Other	88			-	88	
Σ	263			7.0	270	
Passenger	133			4.0	137	Year 1985
Freight	54			4.5	58.5	
Other	94			-		
Σ	281			8.5	289.5	

Table 12-11

Assumed specific energy consumptions for cars. All scenarios (%)

Vehicle \ Year		1975				1985				2005				2025			
		Vehicle mass m	Motion resist. μ	Power train eff. η	Sp. energy consump. e'	m	μ	η	e'	m	μ	η	e'	m	μ	η	e'
IC engines	C_xH_y	100 (1150 kg)	100 (0.040)	100 (0.15)	100 ($3.1\ \frac{kJ}{m}$)	96	95	100	90	83	88	120	60	70	83	145	39
	Methanol					96	95	120	74	83	88	130	54	70	83	170	34
	H_2					96	95	130	68	83	88	150	50	70	83	180	32
Battery power						200	95	330	48	87	88	430	18	74	83	500	12
Fuel cell	Methanol H_2					150	95	270	45	87	88	330	23	74	83	400	15

Note 1: Specific energy consumption e' is the energy equivalent of energy carrier on board required to propel the vehicle one unit of distance; (e') = (kJ/m). For battery cars the energy refers to the AC outlet (which plugs into the charging device).

2: The reference data (100 %) apply to the typical 1975 C_xH_y IC car, here represented by the Swedish SAAB with data evaluated from both FDC-U and FDC-H, which give the specific energy consumption e' = 3.1 kJ/m (approx. corresponding to a spec. fuel consumption of 1.0 liter petrol per 10 km).

1975 SAAB auto
$m = 1150$ kg
$\mu = 0.040$
$\eta = 0.15$

$$e' = \frac{m\,\mu\,g}{\eta} = 3.1\ \left(\frac{kJ}{m}\right)$$ (see text for definitions).

Table 12-12

Assumed specific energy consumptions for buses and freight vehicles. All scenarios (%).

Vehicle / Year		1975				1985				2005				2025			
		Vehicle mass m	Motion resist. μ	Power train eff. η	Sp. energy consump. e'	m	μ	η	e'	m	μ	η	e'	m	μ	η	e'
IC engines	C_xH_y	100	100	100	100	100	95	100	95	90 (100)	88	110	72 (80)	80 (100)	83	120	55 (69)
	Methanol					100	95	110	86	90	88	120	66 (73)	80	83	128	52 (65)
	H_2					100	95	120	79	90	88	130	61	80	83	135	49
Battery power						100	95	250	38	100	88	325	27	90 (100)	83	375	20
Fuel cell	Methanol																22
	H_2					100	95	200	48	100	88	250	35	90 (100)	83	300	25 (28)

Note 1: Numbers within paranthesis apply to freight vehicles. Other data apply to buses. A position without data in paranthesis means that the same figure is applicable to both bus and freight vehicles.

2: See notes in Table 12-10.

3: The reference data (e' = 100 %, 1975 I.C. C_xH_y) are Bus e' = 12.2 (kJ/m)
Lorry e' = 13.0 (kJ/m)

Table 12-14

Energy carrier consumption. Alternatives 1 and 2 for scenario A - Nuclear
Years 2005 and 2025

Transport mode	Energy carriers (PJ)					
	C_xH_y	CH_3OH	H_2	Electr.	Σ	
ALTERNATIVE 1 (ELECTRICITY)						
Passenger	120			13	133	Year 2005
Freight	64			6	70	
Other	164			1	165	
Σ	348			20	368	
Passenger	90			21	111	Year 2025
Freight	64			8	72	
Other	163			2	165	
Σ	317			31	348	
ALTERNATIVE 2 (HIGH H_2)						
Passenger	70		43	10	123	Year 2005
Freight	33		25	6	64	
Other	162		3	1	166	
Σ	265		71	17	353	
Passenger	5		64	18	87	Year 2025
Freight	2		51	8	61	
Other	143		20	2	165	
Σ	150		135	28	313	

Table 12-15

Energy carrier consumption. Alternatives 1 and 2 for scenario B - Biomass
Years 2005 and 2025

Transport mode	Energy carriers (PJ)					
	C_xH_y	CH_3OH	H_2	Electr.	Σ	
ALTERNATIVE 1 (METHANOL - BATTERY ELECTRIC)						
Passenger	70	51		9	130	Year 2005
Freight	33	26		6	65	
Other	150	30		-	180	
Σ	253	107		15	375	
Passenger	8	70		16	94	Year 2025
Freight	4	52		8	64	
Other	120	60			180	
Σ	132	182		24	338	
ALTERNATIVE 2 (METHANOL ONLY)						
Passenger	73	53		7	133	Year 2005
Freight	33	26		6	65	
Other	158	32		-	190	
Σ	264	111		13	388	
Passenger	8	78		13	99	Year 2025
Freight	4	52		8	64	
Other	120	66		-	186	
Σ	132	196		21	349	

Table 12-16

Energy carrier consumption. Alternatives 1 and 2 for scenario C - Synthetic
Years 2005 and 2025

Transport mode	Energy carriers (PJ)					
	C_xH_y	CH_3OH	H_2	Electr.	Σ	
ALTERNATIVE 1 ("SPONTANEOUS")						
Passenger	127			10	137	Year 2005
Freight	64			6	70	
Other	196				196	
Σ	387			16	403	
Passenger	101			18	119	Year 2025
Freight	64			8	72	
Other	195			1	196	
Σ	360			27	387	
ALTERNATIVE 2 (LOW H_2)						
Passenger	122		3	9	134	Year 2005
Freight	62		1	6	69	
Other	196				196	
Σ	380		4	15	399	
Passenger	79		12	16	107	Year 2025
Freight	59		3	8	70	
Other	192		3	1	196	
Σ	330		16	25	373	

12.9 Overall economic structurization

In the economic calculations, the following domains are considered:

- Vehicle manufacturing industry
- Fuel distribution and service & maintenance
- Energy carrier cost

All cost calculations are made relative to a "spontaneous" development, which is characterized by C_xH_y liquid fuelled vehicles plus a minor fraction of electrical vehicles. As liquid hydrocarbons (C_xH_y fuel), natural or synthetic, are available in all scenarios according to the directives for this study, the C_xH_y fuelled transportation is the natural reference state for comparisons.

For the heterogeneous group "other transport", the corresponding alternative fuel distribution costs are estimated to be in proportion to the alternative energy carrier consumption within the scenario in question (see Tables 12-14 to 12-16).

Unless otherwise stated, all costs are given a constant 1978 currency (normally the Swedish crown). Further, a real interest of 4 % is applied.

The nominal costs calculated have the character of "extra" costs corresponding to "extra" equipment, facilities, personnel, etc, required for introducing the alternative energy carriers. However, in those alternatives where a major breakthrough of the new technique is achieved within the time horizon, the disengagement of traditional technology will free resources to support the new technology. It is difficult to estimate what fraction of the nominal costs as estimated today could be termed "extra" costs in the future, and this can only be solved by a broad-outline systems analysis. Closely related to this issue is the possible cost decrease because of technical development (for instance electronics) and increasing unit numbers in mass-fabrication (for instance component manufacture), and the cost increase because of possible resource shortages (for instance certain metals). Necessary assumptions regarding this issue are given further on.

12.10 Transition costs for alternative fuel systems

According to the general assumptions for this study, it may be assumed that an international infrastructure based on the energy carrier in question will gradually develop during the time horizon involved. This means that the systems or components required (for instance fuel cells) do not need to be developed in Sweden but could also be imported or licence manufactured, whichever would be the most advantageous procedure.

The competition between alternative fuels is characterized by different investment requirements, different energy utilization and consumption and different costs. A comparison of different transportation fuel technologies in the scenarios may thus be made by comparing the extra costs involved in changing from a liquid hydrocarbon reference state. Obviously, the more the fuel deviates from the technology of today, the greater will be the required investments. This issue is of course also coupled to the intensity of the assumed transition, that is, the inflow of the new technology. The prescribed energy carrier prices do not seem to be so different that a "best" fuel could be found by this means alone. Consequently, a futuristic fuel like hydrogen would be put at a disadvantage by requiring heavy investments in order to be feasible. Unfortunately, the payoffs are difficult to quantify in economic terms but qualitatively, it is clear that an increase in the use of hydrogen will lead to an increasing improvement in the emission situation and thus to an improvement in the general environmental quality. Also, a diminished use of (foreign) fossil fuel resources is generally desirable. Furthermore, as hydrogen itself may promote the development of efficient propulsion systems, such as fuel cells, the total energy requirements may become lower as compared to the situation with other fuels.

12.10.1 Car manufacturing industry

The Swedish car industry supplies about 35 - 40 % of the inflow of new domestic cars. A large fraction is also exported. Other characteristics of the Swedish car industry structure are the absence of typical car component manufacture and a relatively high cost level. It is thus important that developments should be internationally coordinated and that the production cost picture in Sweden will not be prohibitive for exports.

The time horizon for planning by car manufacturers is in the range of 10 - 20 years. Large deviations from present IC hydrocarbon fuel technology may require a total redesigning of the vehicle (car body, engine and transmission). If it is assumed that an introduction of hydrogen or alternative fuel vehicles will start during the late nineties, then action towards this goal must be taken already in the early eighties.

Present-day development costs for one new type of car with a conventional IC engine are about 2 - 3 Gcr (42), including tooling and production facilities.

In the transition process, the IC C_xH_y vehicle population will be partly replaced by hydrogen fuelled vehicles. This may be done by converting ordinary IC automobiles to hydrogen, by engine modification and by the incorporation of hydrogen storage tanks. The operations involved may be performed at the consumer level provided that suitable facilities are available and that the car manufacturers have prepared the cars for this conversion.

At the production level, it is assumed that the cost of conventional C_xH_y IC car is about the same as for those which have been prepared for hydrogen. As the net effect is due to an interplay between emission, safety and new component cost issues, the potentially brighter emission situation for hydrogen cars may compensate for otherwise higher costs.

As regards FC cars, it is assumed that the car manufacturer will provide the car body and the systems technology for incorporating the fuel cell propulsion system. The latter will originate from other industrial sources. For the moment it seems probable that a fuel cell propulsion system will be licence manufactured in Sweden rather than purely imported or developed and manufactured.

From data in the literature (43 - 44) it is estimated that an FC H_2 car will cost roughly 1.5 times as much as an IC C_xH_y car towards the turn of the century. Taking a typical Swedish car price, 40000 cr (1978), and a manufacturing cost which is approximately 30 % of the sales price, the manufacturers extra cost in a transition will thus be about 6000 cr per vehicle at the production level. This is assumed to apply on average up to the years around 2015; thereafter production costs are assumed to be about the same, considering the mounting costs of anti-emission devices and (probably) diminishing costs of fuel cell systems.

The on-board hydrogen storage system, here assumed to be of a hydride tank type, is about the same regardless of its ultimate use (in an IC or FC hydrogen vehicle). It is uncertain whether the hydride tanks will be developed and manufactured in Sweden, imported or licence manufactured. The cost picture and the life cycle are also unclear; the cost depends mainly on whether critical resource materials are involved, and the useful life depends on whether the hydride can be protected from impurities. The price of a fairly common base material like magnesium was 0.84 US dollars per kg in 1974. Since magnesium is abundantly available and manufactured by electrolysis, its price may be assumed to follow that of electricity. As no large quantities of hydrides have been manufactured and their corresponding costs, useful lives and recycling possibilities are rather unknown, a cost of 10 cr/kg for a future hypothetical hydride is assumed here (45). The adsorption performance of the hydride of the future is assumed to be about 10 % hydrogen up to the time around 2010 and thereafter about 15 % hydrogen. The price is assumed to follow that of electricity.

Energy carriers, such as electricity, methanol, synthetic hydrocarbons etc, are the potential future competitors to hydrogen. From the point of view of the car manufacturers, synthetic hydrocarbons will involve the least deviations from traditional technology. Apart from normal product development, no special "new" car types are required.

Methanol is quite easily incorporated into conventional IC car technology. In (46) it is estimated that a car modified for methanol will be about 5 % more expensive than its petrol counterpart. In order to fully utilize the potential of methanol and possibly to give the vehicle a hydrocarbon interchangeability (for instance by using the λ-probe electronics technology), it is assumed that a new car type, if required, has a nominal development cost of 2 Gcr.

Although methanol is a suitable fuel for fuel cells, the automotive methanol fuel-cell will cost about 10 times more than its hydrogen counterpart. However, as a methanol FC vehicle does not need the hydride tank, its production cost is assumed to be the same as in the hydrogen case mentioned above, i.e. 1.5 times as much as an IC C_xH_y equivalent. The corresponding new car type is assumed to have nominal development costs of around 3 Gcr.

Present Swedish technology in the field of battery powered electric propulsion systems might form the basis for a future domestic industry, manufacturing battery propulsion systems. Again it is assumed that the car industry will provide the car body and the systems technology. Judging from the literature, for instance (44), an electric car will cost roughly the same as its IC C_xH_y counterpart at the production level.

Turning now to the Swedish manufacturers of heavy lorries, this industrial branch is even more dependent on exports. About 85 - 90 % of the lorries manufactured are exported. An international transition towards alternative transportation fuels will thus force this industrial division to similar developments in order to be internationally competitive.

Present development costs for a new long range freight vehicle (47) can be split up as follows:

Vehicle body	0.4 Gcr
Driver's cabin	0.1 Gcr
Engine	0.3 Gcr
Transmission	0.3 Gcr

The time scale involved is around 6 - 12 years depending on the availability of resources from competing programs.

As regards the development of a hydrogen freight vehicle, it is estimated that the IC H_2 lorry requires a development cost of around 1.0 Gcr. At the production level, the extra cost is mainly limited to the incorporation of a hydride tank.

The FC H_2 freight vehicle, with the fuel-cell propulsion system licence manufactured in Sweden, requires about 0.5 Gcr in structure development costs. At the production level, the extra cost of every fuel-cell propulsion system is estimated to be around 25000 cr.

12.10.1.1 Investment requirements in the car manufacturing industry

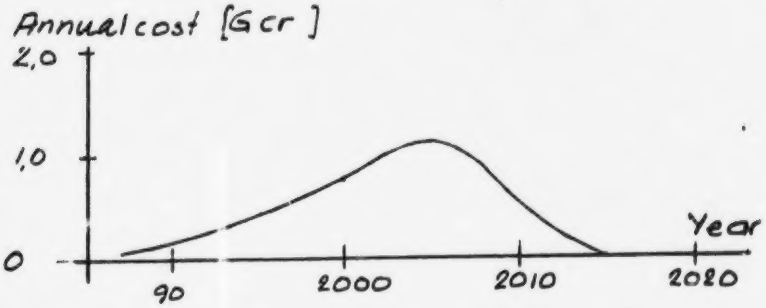
As stated elsewhere, a Swedish industry manufacturing battery propulsion systems might be feasible in various energy supply scenarios. As a rough average, the output capacity could be 10^4 - 10^5 units per year during the later part of the time horizon involved. The cost of developing such an industry is hard to estimate but it could possibly be around 10 - 20 Gcr; this is disregarded here.

Table 12-17 shows the car manufacturer's extra costs for the assumed alternative fuel transition schemes. The vehicle mixture was given in Figures 12-26 to 12-28. The items mentioned and the corresponding costs are assumed to have an "extra" character up to the year 2015. These costs together with their assumed spread in time are shown in Figure 12-29.

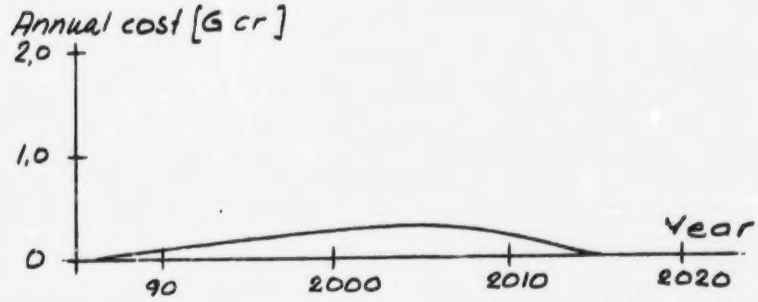
Table 12-17

Manufacturers' costs for changeover to new fuel systems.

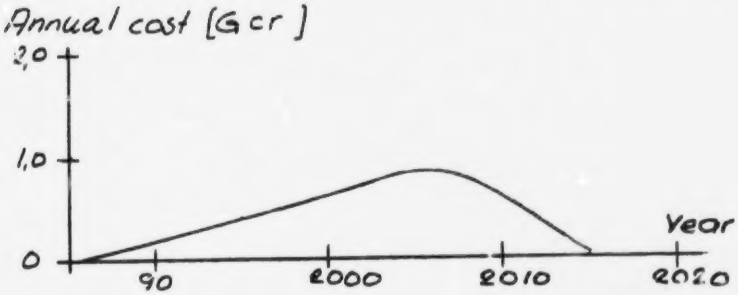
	Gcr
SCENARIO A (NUCLEAR)	
Alt. 1 Electricity	
(Battery propulsion system industry	10 - 20)
Two Battery-electric car models	4 - 6
Alt. 2 High H_2	
One IC H_2 car model	2 - 3
One FC H_2 car model	3 - 4
Extra production costs incl. hydride tanks	2 - 4
One IC H_2 freight vehicle	1 - 2
One FC H_2 freight vehicle	
Extra production costs incl. hydride tanks	1 - 2
SCENARIO B (BIOMASS)	
Alt. 1 Methanol-battery electric	
One IC Methanol car model	2 - 3
One FC Methanol car model	3 - 4
Extra production cost	1 - 2
One IC Methanol freight vehicle	1 - 2
One FC Methanol freight vehicle	
Extra production cost	~ 1
Alt. 2 Methanol only	
Same cost structure as Alt. 1	
SCENARIO C (SYNTHETIC-GAS)	
Alt. 1 "Spontaneous"	
This corresponds to a reference state for all other scenarios and alternatives and is characterized by a "normal" product development	
Alt. 2 Low H_2	
One FC H_2 car model	3 - 4
Extra production cost incl. hydride tanks	2 - 3



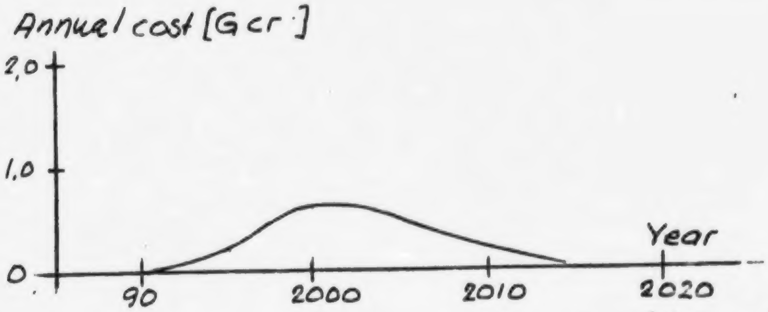
Scenario A (Alt. 2)



Scenario A (Alt. 1)



Scenario B (Alts.1 and 2)



Scenario : C (Alt 2)

Figure 12-29

Annual extra costs for the car industry as compared to the "spontaneous" reference scenario c (Alt. 1).

Note: A battery propulsion system industry, although feasible, is not included in any scenario.

12.10.2 Fuel distribution, servicing and maintenance with alternative propulsion systems

The present fuel distribution network, ending with petrol stations at the consumer level, is strongly tied to liquid hydrocarbons. Although natural liquid hydrocarbons may become rare in the future, synthetic equivalents can be manufactured and gradually introduced into the existing network. This situation would correspond to a "spontaneous" development. However, even minor modifications of this structure, for instance a change-over to alcohol fuels, will require considerable time and efforts for a breakthrough. Major modifications, such as the introduction of hydrogen, will lead to even harder economic impacts. In particular during the transition stage, hydrogen filling stations must exist together with traditional petrol stations, which means high extra costs as compared to a "spontaneous" development. However, as a breakthrough is achieved, earlier traditional systems will phase out, resources will be freed and directed towards the new technology and thus the earlier nominal "extra costs" associated with new hydrogen systems will gradually diminish.

If hydrogen is introduced with a low intensity, associated extra costs will probably have an "extra" character for a long time. On the other hand, a high-intensity introduction will after a certain time lead to gradually diminshing extra costs.

Usually, petrol stations are owned or franchised by oil companies. The mere existence of alternatively fuelled vehicles, imported or domestically manufactured, requires an organized distribution network for them. Moreover, alternatively fuelled vehicles, in order to be accepted at the consumer level, will also require facilities for repair, servicing and general maintenance.

The present car repair and maintenance sector has an annual turnover of about 6.7 Gcr (48). Of this, spare parts account for around 3.7 Gcr. A large single item in vehicle repairs is the changing of exhaust systems, with a turnover of about 1.0 Gcr (materials 0.7 Gcr and labour costs 0.3 Gcr).

A calculation of car ownership economics (49) shows the following annual operating costs for a new car with a sales price of around 40000 cr (capital costs not included):

Petrol cost (1.70 cr/l 1978) (15000 km per year)	2800 cr
Repair and maintenance	2200
Tyres	400
Insurance	1600
Taxes	700
Servicing and parking	1300
Total	9000 cr/year

A suitable scheme for the introduction of an alternative fuel could be to erect largely independent refuelling modules at selected, existing petrol stations and successively to increase their number with increasing demand for the alternative fuel. This module principle actually exists, since it was introduced by the Swedish oil company OK in 1973. In its present basic form, the module is a non-staffed, transportable filling station with a total fuel capacity of 25 m^3. It was originally intended for setting up in places where ordinary service stations cannot be built for economical reasons, Figure 12-30 (50). It is connected by telephone to the nearest OK depot, which receives a warning in case of leakage, power failure, burglary, etc. Because of highly developed automization, operating costs are lower and prices may thus be lower. However, these modules have not yet proved to be rewarding.

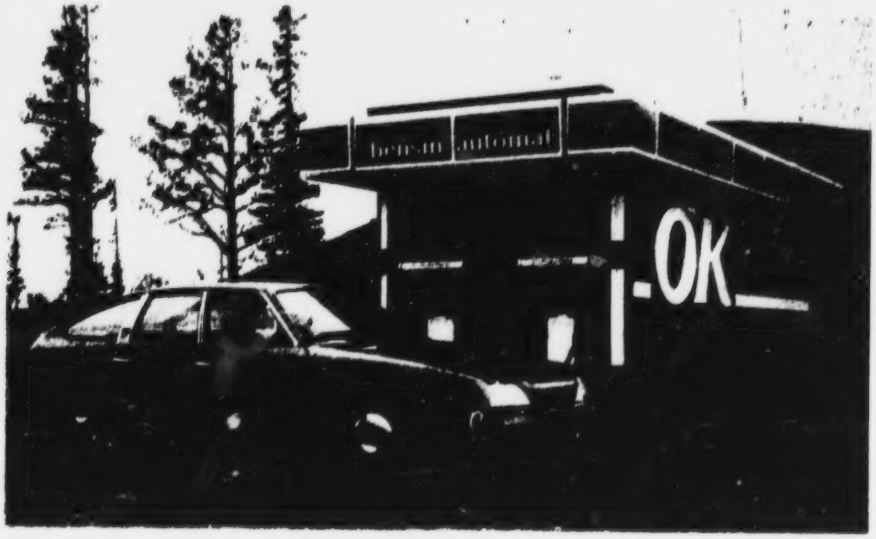


Figure 12-30

Prototype fuelling module (50).

The introduction of alternative fuels and alternative propulsion systems will require an extended capacity for repairs, modifications, servicing and maintenance. It is not clear whether the traditional vehicle servicing structure can meet this requirement, especially during the transition period, when conventional vehicles still have to be dealt with. In addition, safety issues when hydrogen vehicles are introduced into ordinary repair workshops may be far-reaching.

Instead it is suggested that a new servicing and maintenance structure should evolve, coordinated in time and close to the new fuel distribution structure of the alternative technology. The introduction of fuel distribution modules should be linked to a similar introduction of servicing and maintenance facilities. In this way, a resource concentration is achieved, and safety problems can be effectively dealt with as this process will start at selected sites.

Actually, a starting pattern for such a structure already exists. Towards the end of the 1950's the Swedish oil company OK started to build complete car servicing stations as a complement to ordinary filling stations. Such a service station offers the consumer several possibilities apart from pure fuel filling as it consists of a workshop, a "do-it-yourself" hall with around 6 - 12 spaces where motorists themselves can carry out repair and maintenance work with their own or rented tools, and a shop offering car servicing items among other things. Today in Sweden there exist about 1700 stations of this kind; around 80 % of these are managed by OK.

It is thus suggested that the introduction of alternative fuels should start by incorporating fuel modules, preferably at existing car servicing stations with suitable locations. At the same time the workshop and "do-it-yourself" capacity of the station should be greatly increased.

12.10.2.1 Characteristics of servicing and maintenance for alternative vehicles

12.10.2.1.1 Methanol fuelled IC vehicles

In the appropriate scenario, this alternative propulsion system is assumed to be introduced with a starting period around 1990. During the late eighties, the car manufacturers will prepare some of their vehicles for later conversion to methanol. The actual conversion may take place at the consumer level, for instance in "do-it-yourself" facilities.

12.10.2.1.2 Hydrogen fuelled IC vehicles

In the appropriate scenarios, an introduction with a starting period around 1990 is assumed. Here again car manufacturers may prepare some of their products for subsequent conversion to hydrogen. The conversion may take place at the consumer level in the "do-it-yourself" facilities.

Several petrol-to-hydrogen converted cars (and buses) have already been successfully operated, and therefore some experience is available regarding the conversion operation. Usually, the modification requires the incorporation of a special gas mixer, possible changes in engine compression and spark timing, disconnection of the emission control equipment and the incorporation of a hydrogen storage system (pressurized gaseous hydrogen, liquid hydrogen in dewars or hydrogen absorbed in hydride tanks). In this study, only the hydrogen absorption storage is considered. The existing carburettor and petrol fuel tank are retained but instead they are operated with water, which helps to control combustion and suppress the formation of nitrogen oxide. The issue of water additions to IC engines is an old one, but a satisfactory practical solution has yet to appear, for instance regarding the freezing risk. However, the water addition system could possibly be dispensed with during wintertime or else the water could be mixed with a suitable quantity of anti-freeze chemicals. In a specific case, the cost (1975) of such a conversion was estimated to around 440 US dollars, including a high-pressure-vessel hydrogen storage system (51).

12.10.2.1.3 Fuel cell powered vehicles fuelled with hydrogen or methanol

In the appropriate scenarios, an introduction is supposed to start around the year 2000. It is difficult to estimate the required fuel cell servicing capacity. At one end of the scale, there could be only a small demand for maintenance because of a "modular" design; if a malfunction is indicated (electronically) the entire module is simply replaced. On the other hand, judging from practical experience and the history of technology, the first consumers may have the attitude of enthusiasts and engineers, so that a large do-it-yourself capacity is required, especially as a new system often suffers a series of "teething troubles".

As regards the supervised do-it-yourself capacity at the service stations, it is assumed that each methanol or hydrogen fuelled or battery powered vehicle will require on average an annual servicing period of about five days.

The refilling of hydride tanks is performed by supplying pure gaseous pressurized hydrogen. Judging from present-day technology, a hydrogen pressure of about 5 MPa will give a tanking time of some minutes with fresh traditional hydrides. Future developments might well bring forth hydride tanks which have a reasonably rapid hydrogen absorption at considerably lower pressures. On the other hand, worn-out hydrides may require elevated pressures to give reasonable tanking times.

12.10.2.1.4 Battery powered vehicles

Battery powered cars are not assumed to dominate in any of the given scenarios but are incorporated in most of the alternatives. The main reason for incorporating battery vehicles in the "spontaneous" development case is their favourable environmental impact, especially for intra-regional traffic within cities. An introduction of these vehicles is assumed to start around 1990.

As regards the "fuel", battery powered vehicles have a very special position. Electricity can be generated at large power plants, more or less independently of formal scenario boundaries and using a wide range of primary energy carriers. Moreover, combustion generated emissions are concentrated entirely to the electricity generating plant. They are thus absent from the sensitive environment of the end-user. Furthermore, the "fuel" distribution infrastructure exists already in the form of the ordinary electricity network. The major drawbacks in this bright picture are the long refuelling times (hours instead of minutes) and the limited vehicle range, requiring frequent refuelling.

Batteries should preferably be recharged at the consumer level during nights, when cheap electricity is available. Many vehicle parking areas are already supplied with electricity for wintertime parking heaters. Alternatively, battery packs could be changed at the servicing stations.

Finally, batteries may be rapidly recharged at servicing stations. This process requires special equipment and safety measures. The balance between these refuelling processes is estimated to be roughly as follows: 60 % recharging at parking sites; 35 - 40 % battery change and 0 - 5 % rapid recharge.

As regards repair and maintenance at the "do-it-yourself" facilities, the same principles should apply as were mentioned in connection with fuel-cell vehicles (which are also characterized by electric propulsion with an intermediate battery).

12.10.2.2 Economic structure of servicing stations

A schematic layout of a typical servicing station is shown in Figure 12-31. It consists of sections for fuel refilling, a workshop, about 10 do-it-yourself bays, car accessory shop and administrative routines (52).

Typical annual turnovers are:

Fuel ~ 3000 - 5000 m^3

Do-it-yourself space ~ 15 - 25 Kcr per place

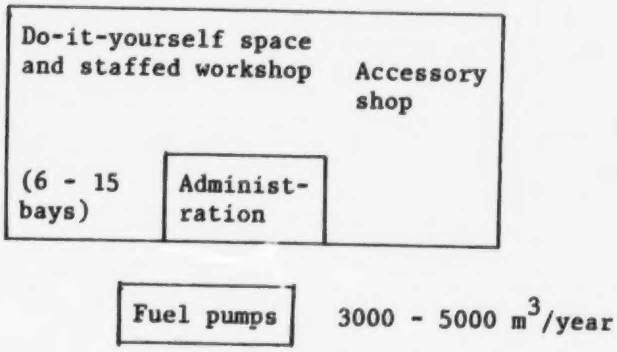
Shop ~ 10 - 25 Kcr per m^2

Total ~ 10 - 15 Mcr

The capital investment for the station is about 8 Mcr and the number of employees is around 10 - 12. With a real interest rate of 12 %* and an expected lifetime of 20 years, the following annual cost data are obtained:

Annuity	1.07 Mcr
Operating and maintenance	1.0 Mcr

The capital investment for the non-staffed filling station module, illustrated schematically in Figure 12-32, is around 0.3 Mcr.



Area of building ~ 600 - 700 m^2

Total area of land ~ 1500 - 2000 m^2

Figure 12-31

Schematic layout of a typical car servicing station of today.

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* Used by the OK Union. For this study a real interest rate of 4 % is prescribed, and this value will be used in the calculations further on.

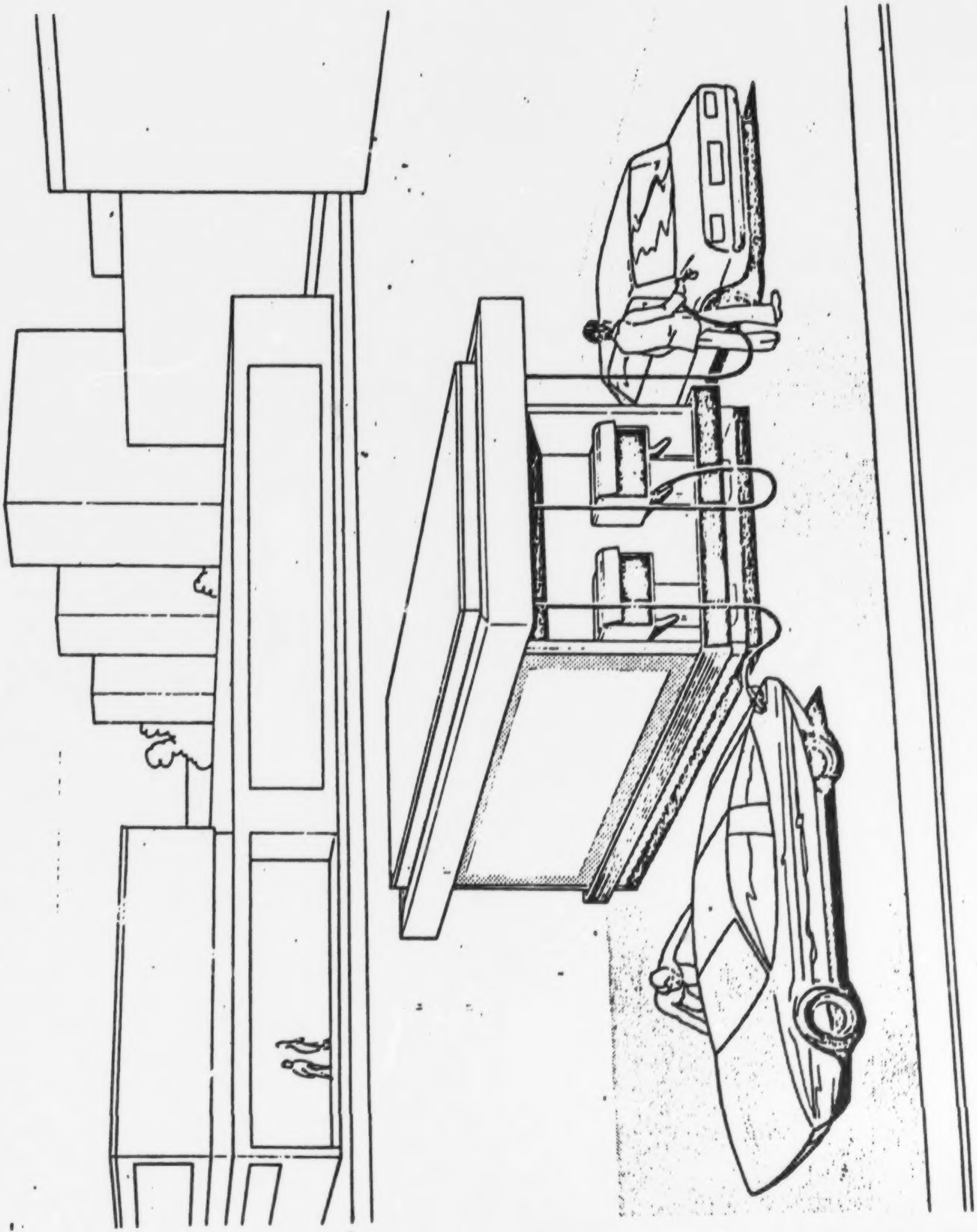

Figure 12-32

Schematic sketch of an alternative fuel filling module to be developed from the OK Union's basic design (52).

12.10.2.3 Cost structure of an early hydrogen servicing station

The hydrogen fuel will be introduced gradually at selected, existing servicing stations of the above mentioned kind. The facility for the hydrogen filling operation is a fuel module of the basic design shown in Figure 12-32. Hydrogen will be supplied to the station site through a community pipeline. A pressure vessel fed by hydrogen compressors will be used as a buffer.

The annual energy flows of a typical transitional hydrogen servicing station around the year 2005, as estimated from present station characteristics and the future energy carrier proportions, will be

Hydrocarbons	~ 65 TJ
Hydrogen	~ 40 TJ

In some scenarios, hydrocarbon fuels have almost disappeared towards 2025. Nevertheless, a standard hydrogen station size of 40 TJ per year will be kept in all cases. This corresponds to about 900 kg of hydrogen per day which is roughly equivalent to the full tank capacity of 250 - 300 cars. Assuming that each hydrogen filling operation takes around 0.3 h and that filling space is available for 8 h per day, then 5 modules with 2 spaces each, of the kind mentioned above, are required. Thus about 250 vehicles per day may be refuelled. The investment cost of a hydrocarbon module (Figure 12-30) is at present about 0.3 Mcr. It is estimated that the hydrogen equivalent will cost around 0.4 Mcr.

The kinetics of the refuelling of a hydride tank depend on the hydrogen supply pressure. In order to ensure an adequately rapid refill process at the station, even with somewhat worn-out hydrides, and to keep the dimensions of the buffer vessel within reasonable limits, a provision is made for increasing the pipeline hydrogen pressure by the use of compressors. The maximum pressure ratio of these is specified to 50, which should give a sufficiently large margin. As a limiting performance requirement, these compressors should be able to work 10 hours a day, which corresponds to a power requirement of about 300 kW assuming adiabatic compression. The investment cost for the compressors is taken from (53) and amounts to about 1.1 Mcr.

The investment cost of a pressure vessel is about 52 cr per standard m^3 hydrogen (54). Its buffer capacity is assumed to equal half a day's consumption, which gives a capital cost of about 0.25 Mcr.

The 40 TJ hydrogen servicing station will provide a year's fuel for 1600 hydrogen fuelled cars around the year 2005. Supposing that each hydrogen car requires 5 working days per year for modifications, servicing, maintenance, etc and assuming that each do-it-yourself space is available 300 days per year, then about 30 supervised do-it-yourself places will be needed.

The investment cost for do-it-yourself space today is estimated to 0.1 Mcr. With an increased degree of sophistication, including safety devices, this cost for the hydrogen station is assumed to be 0.15 Mcr for each place.

Bearing in mind that the hydrogen servicing station will evolve around the classical C_xH_y servicing station, the following economic calculation can be made:

Investment costs

5 hydrogen filling modules, 0.4 Mcr each	= 2.0 Mcr
Compressor	= 1.1
Pressure vessel	= 0.25
Do-it-yourself space incl. equipment, 35 places, 0.15 Mcr each	= 5.25
Total	= 8.6 Mcr

With a 4 % real interest rate and an expected life of 20 years, the capital recovery will be:

Annuity	= 0.63 Mcr
Capital renewal	= 0.1
Subtotal	= 0.73 Mcr

Operating costs

Number of employees: Hydrogen filling 2 - 3, supervisors of do-it-yourself space ~ 8 and administrative ~ 2

Total ~ 12 operators, 80 Kcr each	= 0.96 Mcr
Energy carrier transmission cost*, possible purification, electricity, insurance, etc	= 0.3
Subtotal	= 1.26 Mcr

Thus the total annual cost of a 40 TJ hydrogen servicing station, evolving from an existent C_xH_y servicing station, amounts to about 2.0 Mcr, i.e. 50 cr/GJ or 7 cr/kg H_2.

12.10.2.4 Cost structure of a methanol servicing station

Although methanol-petrol mixtures are feasible for IC engines, only a pure methanol fuel supply is considered here to facilitate the probable development and introduction of methanol fuel cell vehicles within the time horizon of the study.

Methanol can be introduced into the existing equipment of present fuel stations, provided that some components are changed or renovated. However, a methanol introduction scheme analogous to the hydrogen case is regarded as superior and is therefore discussed here. Methanol is gradually introduced into fuel modules of the type shown in Figure 12-32 at selected existing servicing stations. At the same time, the supervised do-it-yourself capacity is enlarged.

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* For details of transmission costs se Chapter 7 in this study.

It is assumed that the typical methanol servicing station will supply 50 TJ of methanol per year. This amounts roughly to 9 m^3 per day, which can be managed by two modules with a total of four filling places. The capital cost of each module is estimated to be 0.35 Mcr.

This methanol servicing station supplies the fuel for about 1800 vehicles per year in 2005. The required do-it-yourself area with 30 places is estimated to carry an investment cost of 0.1 Mcr per place, since it is less sophisticated than in the hydrogen case. The number of employees is assumed to be 5 for the supervised do-it-yourself area and one for administration.

The economy of the station will be as follows:

Investment costs

2 methanol modules at 0.35 Mcr each	= 0.7 Mcr
Do-it-yourself space incl. equipment, 30 places, 0.1 Mcr each	= 3.0
Total	= 3.7 Mcr

With a 4 % real interest rate and an expected life of 20 years, the capital recovery will be:

Annuity	= 0.27 Mcr
Capital renewal	= 0.03
Subtotal	= 0.30 Mcr

Operating costs

Total ~ 6 operators, 80 Kcr each	= 0.48 Mcr
Energy carrier transmission cost, possible purification, electricity, insurance, etc	= 0.1
Subtotal	= 0.58 Mcr

Thus the total annual cost of a 50 TJ methanol servicing station, evolving from an existent C_xH_y servicing station, amounts to about 0.9 Mcr, i.e. 18 cr/GJ or 32 öre/l methanol.

12.10.2.5 Cost structure of a battery servicing station

Extra costs for battery powered vehicles will only appear in those scenarios where the assumed number of these vehicles deviates substantially from the reference "spontaneous" situation.

It is assumed that the required amount of electrical energy for transport is transmitted mainly over existing electrical networks. Moreover, the reloading of batteries is assumed to take place mostly during nighttime. Hence no specific transmission costs will be included, although these (expressed as cr per GJ) are nominally considerable higher than the corresponding costs for chemical fuels.

A standard battery vehicle service module is presumed to consist of 10 do-it-yourself places, one battery exchange place and two employees. If the investment cost of one do-it-yourself place is 0.1 Mcr, and that of one battery exchange place is 0.3 Mcr, the cost structure will be:

Investment costs

10 do-it-yourself places, 0.1 Mcr each		= 1.0 Mcr
1 battery exchange place		= 0.3
	Total	= 1.3 Mcr

With a 4 % real interest rate and an expected life of 20 years, the capital recovery will be:

Annuity		= 0.096 Mcr
Capital renewal		= 0.01
	Subtotal	= 0.106 Mcr

Operating costs

2 operators, 80 Mcr each	= 0.16 Mcr

Thus the total annual cost for this kind of service station module is 0.27 Mcr.

12.10.2.6 Cost of alternative servicing stations for freight vehicles

The infrastructure of fleet operations with freight vehicles differs in character from that of ordinary automobiles. Freight corporations usually possess terminals and central depots of their own, with refuelling and general servicing facilities.

It is assumed that the introduction of alternative fuels such as hydrogen and methanol will occur by the incorporation of the same kind of basic refuelling and servicing modules as were mentioned above. However, considering the possibility of a more concentrated utilization of resources at central depots, the extra cost of a 40 TJ hydrogen module is assumed to be 1.3 Mcr (compared to 2.0 Mcr above) and that of 50 TJ methanol module 0.6 Mcr (compared to 0.9 Mcr above).

12.10.2.7 Total extra cost picture for fuel distribution, servicing and maintenance

The cost evolution during the period under consideration is evaluated using the alternative fuel distribution and servicing station unit with a capacity of 40 TJ hydrogen per year or 50 TJ methanol per year. The numbers of these stations required in the years 2005 and 2025 are determined by the energy carrier consumptions in the respective scenarios, which are given in Tables 12-14 through 12-16.

The calculated nominal costs have the character of "extra" costs corresponding to the "extra" equipment, facilities, personnel, etc required for introducing the alternative energy technology.

Due to advantages in mass fabrication, more rapid technical development etc., it is assumed that an alternative technology breakthrough* of at least 50 % will reduce the nominal cost by 40 %, and above 75 % the reduction will be 70 %.

The cost contribution of "Other transport" is estimated to be proportional to the consumption of alternative fuel within this transportation field. Figure 12-33 shows the cost development vs time.

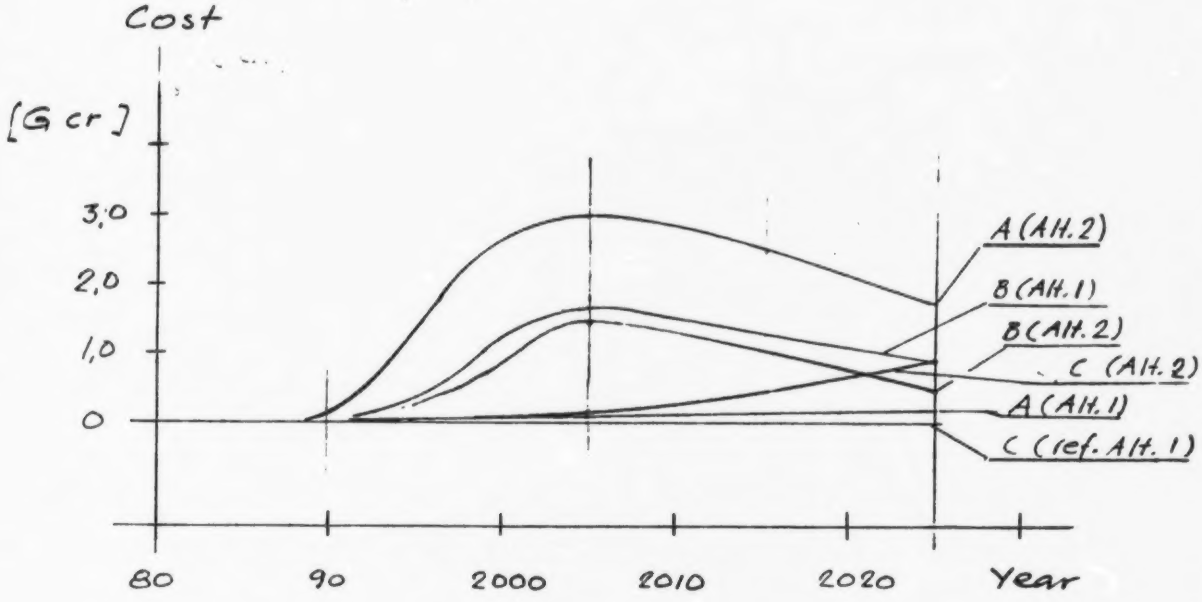

Figure 12-33

Annual extra costs (capital recovery and operating) for alternative fuel distribution and vehicle maintenance at service stations as compared to the "spontaneous" reference scenario C (Alt. 1).

12.10.3 Energy carrier cost

The cost scenario of energy carriers is given in Chapter 5. Table 12-18 shows an excerpt regarding transport fuels. Knowing the energy carrier consumption (Tables 12-13 through 12-16), the total energy carrier cost is obtained, Figure 12-34. Figure 12-35 shows the cost development of energy carriers vs time related to the "spontaneous" reference case. It has been assumed that in 2005 50 % of the hydrocarbon fuels are synthetic and that in 2025 100 % are synthetic. Moreover, it is assumed that in scenario B methanol is manufactured from biomass.

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* defined as $\frac{\text{amount of alternative fuel (PJ)}}{\text{amount of total fuel (PJ)}}$

Table 12-18

Cost development of alternative transport fuels.

Fuel		cr/GJ		
		1985	2005	2025
Petrol		22.2	36.5	61.4
Synthetic petrol		39	51	62
C_xH_y	50 % synth. petrol 2005 100 % -"- 2025		43.8	62
Methanol	from wood	55	58	60
	imported	30	43	52
GH_2 (electrolytic)		42.5	51	62
Electricity		28	39	54

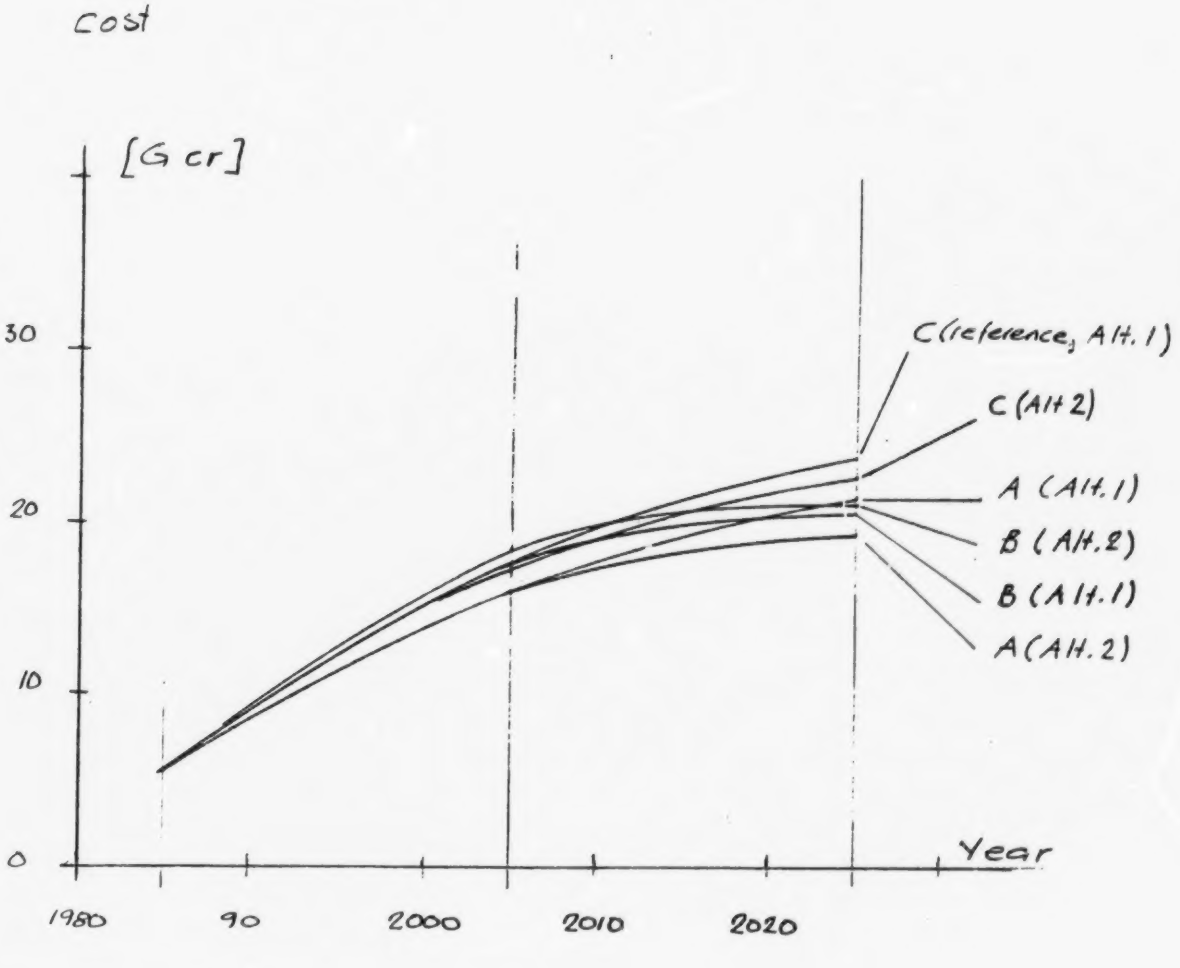


Figure 12-34

Annual cost of transport fuels for different scenarios (A, B, C) vs time.

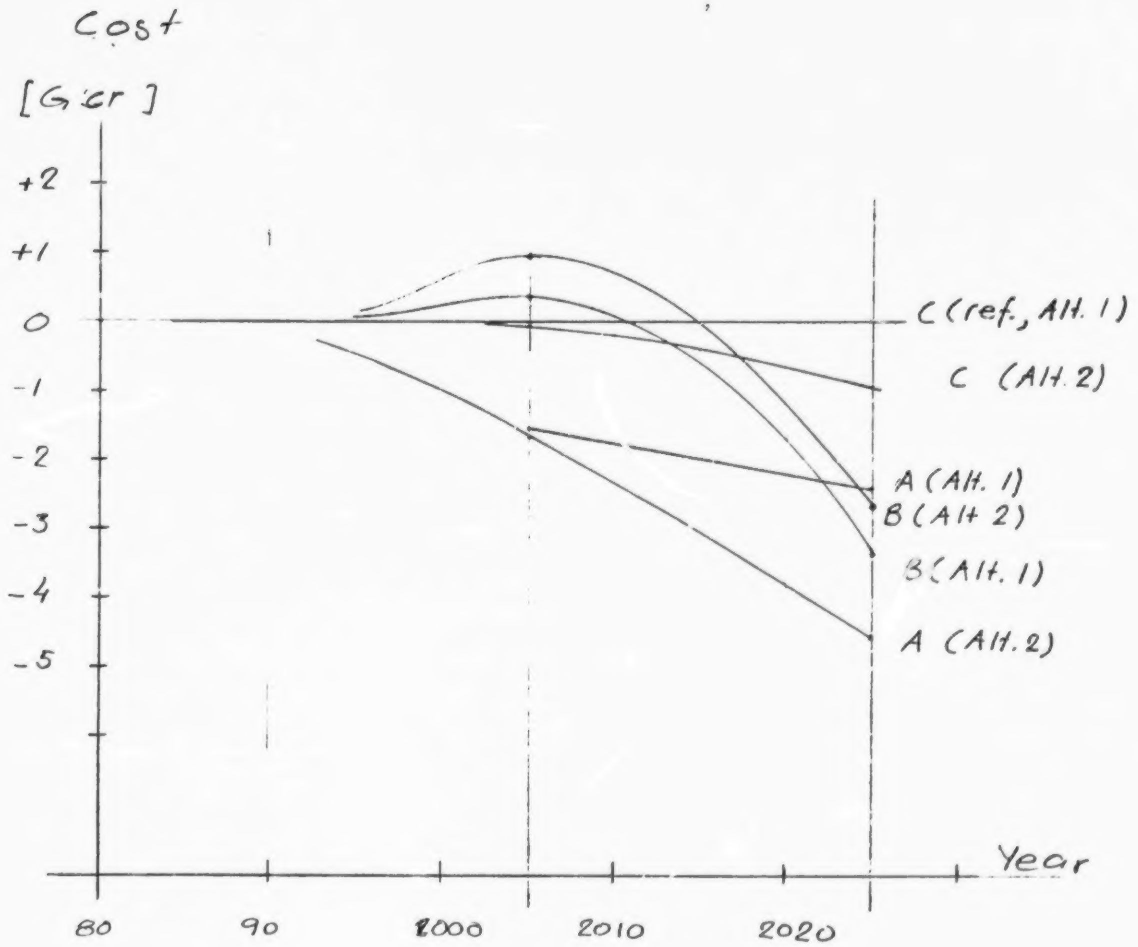


Figure 12-35

Annual fuel cost differences for scenarios A, B and C compared to "spontaneous" reference alternative. (Negative value indicates that the cost of the reference alternative is higher.)

12.11 Summary and conclusions

The cost development within the different scenarios and with regard to

- the automobile industry,
- fuel distribution, servicing and maintenance,
- energy carrier costs,

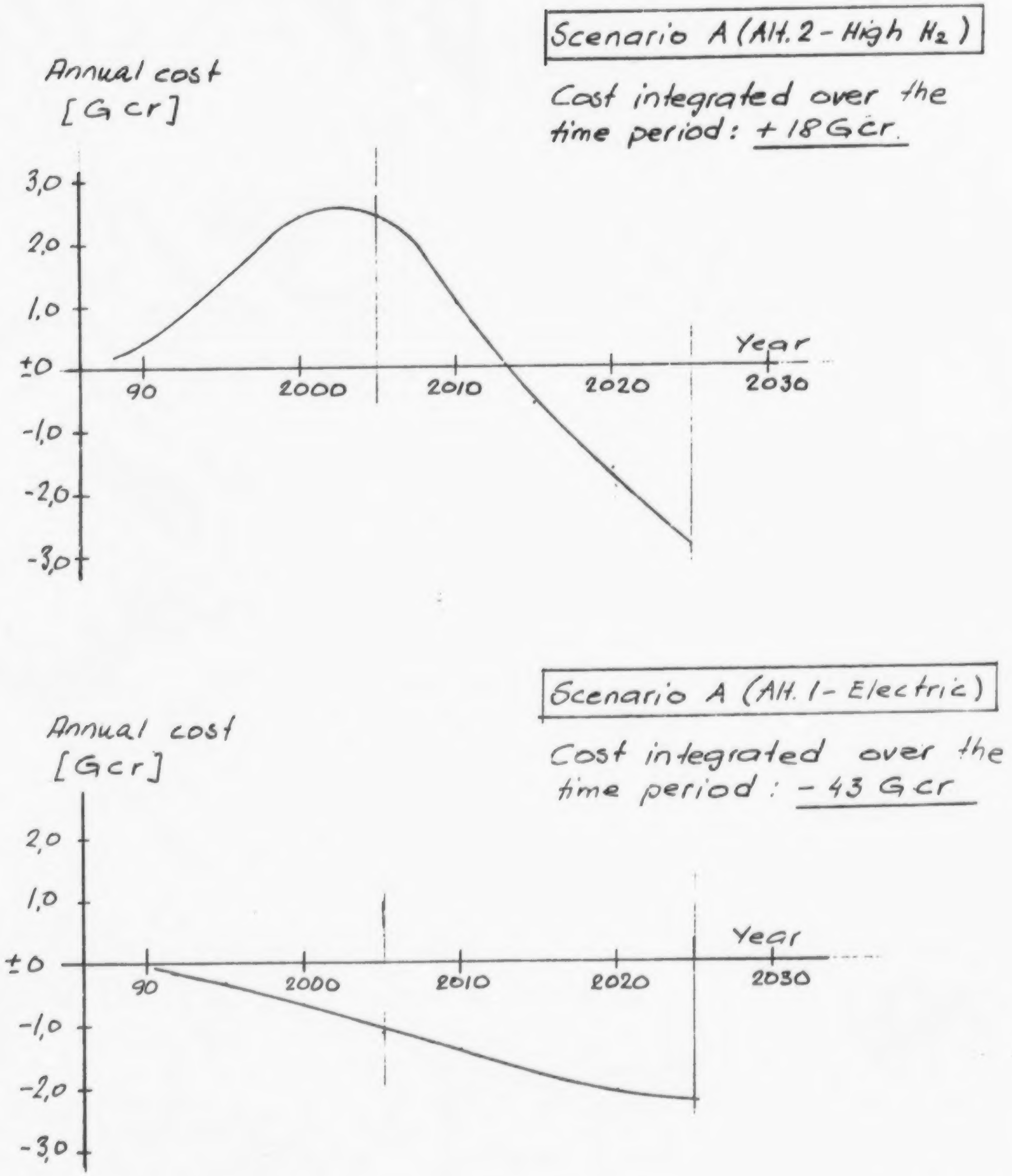
is illustrated in Figures 12-36 to 12-38. For comparison purposes, an integrated cost over the time period is also given in the figures. For the scenarios with hydrogen fuel, Figure 12-39 shows the annual investment costs required for the automobile industry, fuel distribution, servicing and maintenance. The consumption of hydrogen fuel in the years 2005 and 2025 is also indicated.

All costs have been calculated relative to a "spontaneous" development. Obviously, the more a scenario deviates from the "spontaneous" development (which represents an extrapolation of today's conventional technology), the higher will the costs be. Thus, scenarios A (Alt 2 - high hydrogen) and B (biomass) incorporating both alternative fuels and alternative propulsion systems, with an assumed major breakthrough of the new technology, will require the highest transitional costs. However, it seems reasonable to assume that only a fraction of the nominal costs will be thought of as "extra" costs during a major breakthrough, as a corresponding disengagement of traditional technology will free resources to support the new technology.

The cost development for the different energy carriers has been specified in this study. However, as the costs are dependent on the specific manufacturing process, it is assumed that hydrogen is produced electrolytically in all scenarios and that methanol is produced from domestic biomass in scenario B. Difference in energy carrier price and utilization will on the whole put scenario C (Alt. 1 - reference) highest and scenario A (Alt. 2 - electric) lowest in the diagram of annual fuel cost vs time.

The economics of new infrastructure regarding fuel distribution, servicing and maintenance are naturally heavily influenced by deviations from the "spontaneous" development. The techniques and economics of future alternative car servicing stations, functioning at the consumer level, obviously rely on uncertain estimates. This problem has been reduced by using the same standard modular type for all alternative fuel stations.

As regards battery powered vehicles, a certain fraction of these are assumed to be part of the vehicle population in the "spontaneous" development and also of most of the other scenario alternatives. It is assumed that the required amount of electricity is transmitted predominantly through existing electrical networks, so that differences in the infrastructure of electrical energy distribution may be neglected. Thus the cost differences between the scenarios in this respect correspond only to different numbers of electric car servicing stations. With these assumptions, an increased number of battery powered vehicles will generally give a beneficial cost picture.



Scenario A (Alt. 2 - High H_2)

Cost integrated over the time period: +18 Gcr.

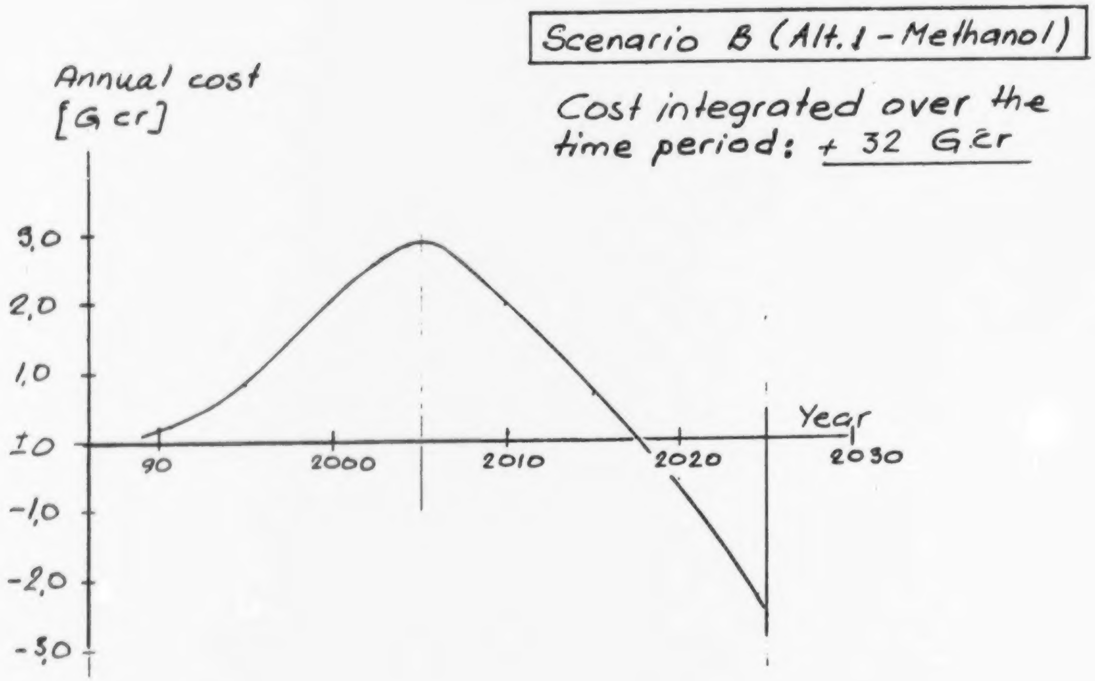
Scenario A (Alt. 1 - Electric)

Cost integrated over the time period: - 43 Gcr

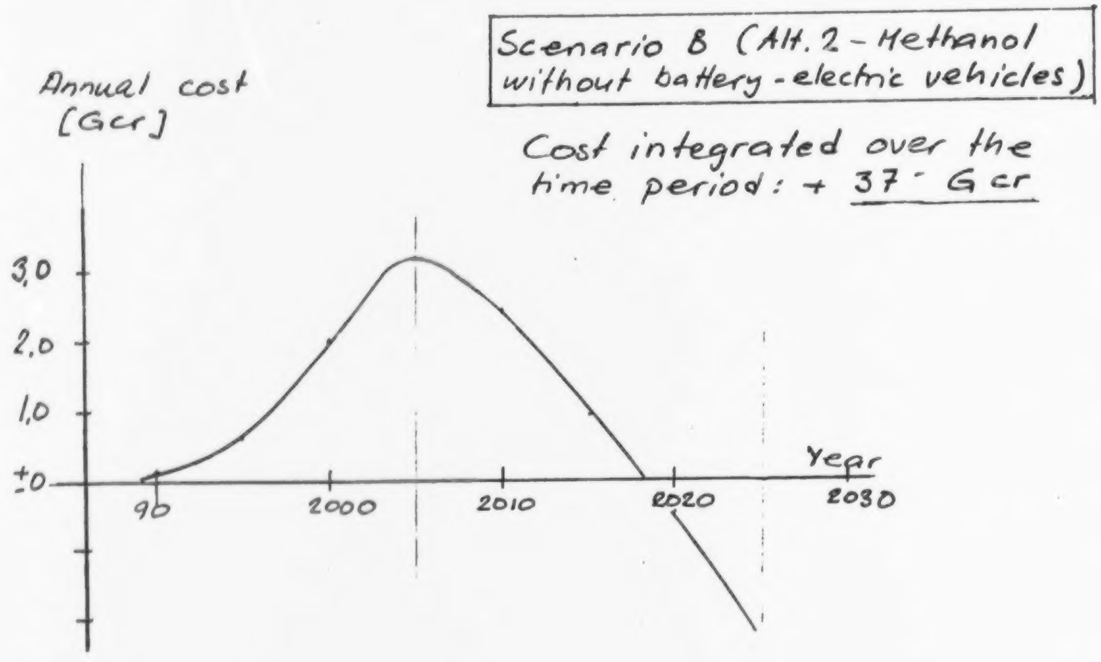
Figure 12-36

Total extra annual costs (fuel, car industry, distribution and maintenance) for different scenarios as compared to the the "spontaneous" reference scenario.

Note: Negative value indicates a gain compared to reference scenario C (Alt. 1).


Scenario B (Alt.1 - Methanol)

Cost integrated over the time period: + 32 G cr


Scenario B (Alt. 2 - Methanol without battery-electric vehicles)

Cost integrated over the time period: + 37 G cr

Figure 12-37

Total extra annual costs (fuel, car industry, distribution and maintenance) for different scenarios as compared to the "spontaneous" reference scenario C (Alt. 1).

Note: Negative value indicates a gain compared to the reference scenario.

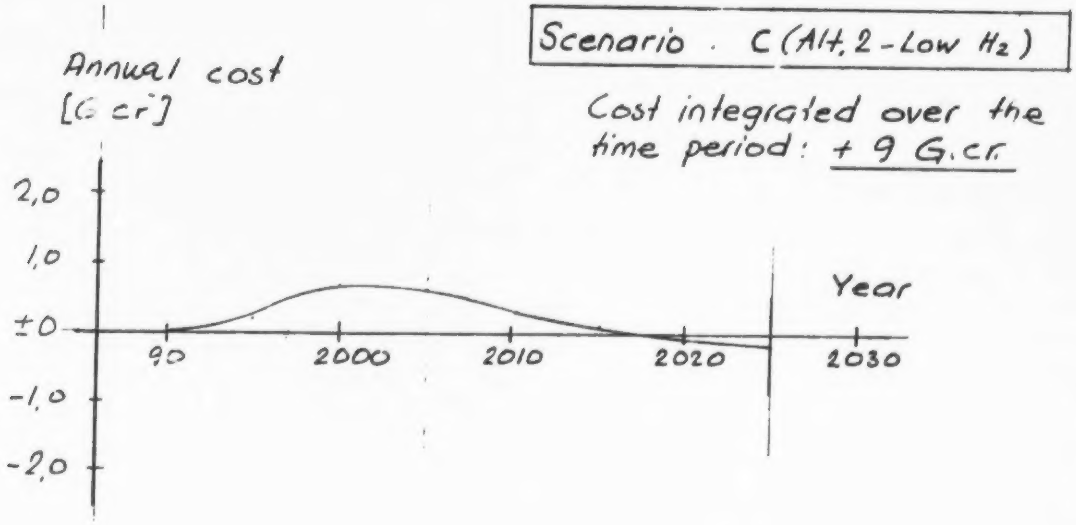
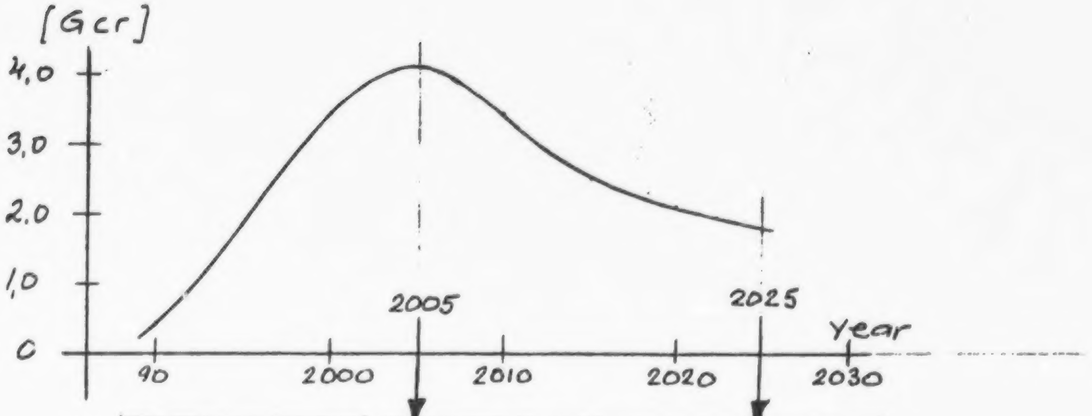


Figure 12-38

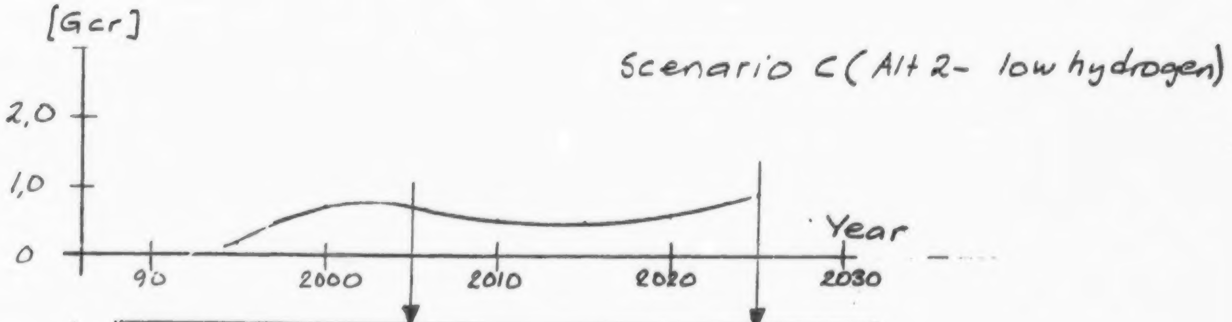
Total extra annual costs (fuel, car industry, distribution and maintenance) for different scenarios as compared to the "spontaneous" reference scenario.

Note: Negative value indicates a gain compared to reference scenario C (Alt. 1).



Hydrogen consumption	71 [PJ]	135 [PJ]
% of total energy cons.	20 %	43 %

Scenario A (Alt 2 - high hydrogen)



Scenario C (Alt 2- low hydrogen)

Hydrogen consumption	4 [PJ]	16 [PJ]
% of total energy cons.	1,0 %	4,3 %

Figure 12-39

Annual investment costs (car industry, fuel distribution, vehicle service and maintenance) for different intensities of hydrogen introduction regarded as a deviation from the "spontaneous" development.

In the overall economic picture of costs vs time, the scenarios with a high-intensity introduction of alternative technology, for instance scenario A (Alt. 1 high H_2) and scenario B, will typically give a maximum annual cost value in the early stages, and thereafter the costs will diminish as the new technology achieves a breakthrough. Scenario A Alt. 2 (electric) will give a generally beneficial cost vs time development, for the reasons indicated above regarding electric vehicles. In the methanol case (Scenario B), the integrated cost during the time horizon adopted here is rather unfavourable, but this depends on the relatively high price of domestic methanol (from wood) used for the calculation.

According to the assumptions of this study, liquid hydrocarbons will be available in all scenarios. This means that the competing alternatives are not necessarily tied to a certain scenario, but could actually be compared/competing across the formal scenario boundaries. For instance, the hydrogen alternatives from scenarios A and C could be incorporated in scenario B (biomass) provided that hydrogen is manufactured by electrolysis. Conversely, the methanol alternatives from scenario B could be incorporated in scenarios A (nuclear) and B (synthetic) provided that methanol is manufactured from biomass.

Although a futuristic alternative fuel like hydrogen will require heavy industrial and infrastructural investments if it is to be feasible, Figure 12-39, the mere process of introduction and use may in itself promote the development of efficient propulsion systems, such as fuel cells, and thus lower the total energy requirements when compared to the use of traditional fuels. Other payoffs are more difficult to quantify, but qualitatively, it is clear that an increase in the use of hydrogen fuel will lead to a direct improvement in the emission situation.

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13. MATERIALS PROBLEMS

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13.1 Introduction

The large scale application of hydrogen as an energy carrier presents unique demands on material properties (see Table 13-1). The major problems arise mainly from hydrogen gas in contact with the containment wall of containers under a wide range of temperatures and pressures, where hydrogen may act alone or synergetically with other damaging phenomena such as corrosion, erosion, oxidation etc.

Table 13-1

Potential materials problems in hydrogen energy systems (1).

Production feedstock	Process heat source	Production technique	Materials problems
Water	Nuclear	Thermochemical split	Hydrogen embrittlement
NG	Solar	Electrolysis	Tritium permeation
Oil	Geothermal	Coal gasification	Corrosion Acids
Coal	Coal	Direct water split	Halides Brine
		Steam reforming	Liquid metals
		Partial oxidation	Heat transfer fluids and salts
			Oxidation Carburization Decarburization Sulphidation Nitridation
			Erosion Coal slurries Heat transfer slurries

In an advanced concept of hydrogen economy, non-metallic components are also expected to play a vital role. However, the overwhelming bulk of materials to be used is expected to be metallic. Accordingly, this report is limited to the problem of hydrogen damage to metallic materials only.

Limited experience in hydrogen handling (see Table 13-2) has painfully demonstrated that material norms based on past experience from petrochemical and natural gas systems must be re-evaluated.

Hydrogen damage to structural alloys has been known for a long time, and the literature on this subject is voluminous. Earlier interests were concentrated on steels containing small amounts of soluble H_2 introduced inadvertently during various manufacturing processes or during service conditions by corrosion or some electrolytic process. The hydrogen embrittlement under this category is generally observed to be most critical at room temperatures and low strain rates or even under static loads. However, problems of hydrogen energy systems have some novel features which must be taken into account.

Table 13-2

Hydrogen storage system failures (1).

Year	Location	Number of failures	Pressure		Material	Type of failure
			MN/m^2	psi		
1964 - 65	Aerojet	5	Ground storage tanks		1146a steel	Nozzle leaks at welds
1965	Aerojet	3	35	5000	A517-F	Cracks up to 1.3 m
1966	NASA	3	20	3000	A517-F	Inner shell cracked and leaked
1967	Aerojet	1	25	3600	A517-F	Cracks up to 1.5 m
-	Sud Aviation	1	120	17000	Maraging	Explosion
			Borudon tubes in pressure gages			
1964 - 67	NASA	-	-	-	403 and 431 stainless steels, Inconel X	Rupture, fire and and injury

13.1.1 Hydrogen production

Among the numerous proposals currently under examination, all except conventional electrolysis of alkaline water are carried out at fairly high temperatures and pressures. Thus, the production of hydrogen from coal, thermal dissociation of water, catalytic beds, thermochemical processes, hydrolysis of metals, metal oxides and halides, chemical heat piping etc all require elevated temperatures and pressures. The material integrity under these severe conditions is not well known. Expected problems are blistering, hydrogen attack, surface cracking and extensive hydrogen permeation. It is possible but not certain that the existing families of ferrous and nickel base alloys may serve the purpose, with judicious modification and/or application of non-permeable surface coatings.

13.1.2 Hydrogen storage

There are three different ways of storing H_2 gas, namely as:

- liquefied H_2
- compressed H_2 gas
- metallic hydrides.

The last two possibilities require the exposure of metallic components to high H_2 pressures and stress-cycling; the hydride containers may be required to sustain even higher temperatures and thermal cycling.

13.1.3 Hydrogen transmission

The pressurized tubes used in pipelines are expected to function under the severe conditions of soil chemistry, environmental corrosion and thermal cyclings (seasonal when buried and diurnal when exposed).

Having enumerated the possible novel features of the demands made on structural materials for applications in hydrogen energy and fossil-fuel economy, an attempt will be made in what follows to catalogue the present day status of the H_2 problem as we observe and understand it.

Methods of material evaluation are also provided, together with some actual examples of experimental results. Because of special interest in the production of H_2 by electrolysis, material problems associated with this process are treated separately.

References (2 - 6) are the major sources of information for this report and should be consulted for detailed information.

13.2 The nature of the hydrogen problem

13.2.1 Permeation

Hydrogen permeates alloys at a much faster rate than other species. The first stage of the process is the dissociation of the H_2 molecule and adsorption of the atomic hydrogen at the surface. The surface binding energy of H atoms is rather large (chemisorption) and varies from metal to metal. In the presence of oxides or other gases adsorbed on the surface (e.g. CO, CH_4), a surface impedance to H_2 adsorption exists.

Following adsorption, hydrogen atoms diffuse to the interior and are absorbed at interstitial positions or to the trapping centres, if present. Typical trapping centres are said to be dislocations, grain boundaries, stacking faults, incoherent and coherent precipitates, inclusions, voids, internal cracks etc. Certain alloying atoms may interact with atomic hydrogen and serve as additional trapping centres.

Hydrogen permeation through iron and steel may be divided into two regions on the temperature scale. The exact boundary between the two regions is not well defined experimentally but ranges from 100 - 300°C for steels of different compositions. High temperature permeation has been found to be proportional to the differential of the square root of the input/output pressures.

Low temperature permeation (at about room temperature) is supposed to be effected by the attractive interaction between the H_2 atom and the trapping centres. Thus, a distinction must be made between the transient and steady state permeation at lower temperatures, because the latter state is approached only after the saturation of trapping centres.

Permeation transients, however, are very much influenced by the composition and processing history of the material while the steady state permeation remains unaffected, as one would expect.

13.2.2 Internal embrittlement

The term internal embrittlement is often used to describe the brittleness caused by the hydrogen retained in a lattice. As has been discussed earlier, due to the high permeability of H_2 there are numerous conditions under which a significant level of H_2 may build up within the lattice.

The effect of internal hydrogen on material brittleness may induce both brittle and ductile types of fractures, which will be presented separately.

13.2.2.1 Brittle fracture

In many alloy systems, particularly at high strength levels, hydrogen embrittlement reveals itself as sustained load cracking (SLC), either in an intergranular, transgranular or mixed mode. The question to be asked is, how does the hydrogen contribute to the process? Is the presence of pre-existing internal damage a necessary precursor to internal hydrogen assisted fracture?

As regards the direct role of H_2 in the fracture process, many possibilities have been suggested, e.g. a change in cohesive energy, a localized pressure increase, interaction between hydrogen and plastic relaxation processes.

Because SLC occurs in many different types of alloys and alloy structures (including stainless steel), the cohesion deterioration concept appears to be doubtful. On the other hand, there is evidence that hydrogen induced cracks (at high supersaturation) may exist, and cracks that already exist (prior to hydrogen introduction) may remain subcritical in the absence of H_2. Thus, cathodically charged stainless steel specimens showed brittle failure under static load. On annealing, as the H_2 was outgassed, the embrittlement was removed which demonstrates the reversible nature of the process.

It thus appears that hydrogen transport to critical sites via thermal and stress (triaxial) assisted diffusion and/or dislocation-assisted dumping is a necessary condition. Softer materials, where the crack tip may be blunted due to localized plastic deformation, are expected to show relative immunity to SLC.

13.2.2.2 Ductile fracture

Although relatively weaker materials are expected to suffer less from SLC (limited plasticity), it has been observed that they may show decreasing reduction of area and a dimpled type of fracture mode in the presence of lattice-retained hydrogen (a more ductile manifestation of H_2 embrittlement). There are now documented cases for hydrogen embrittlement in a host of alloys hitherto considered immune.

The critical strain rate and temperature dependence of the phenomenon has revived the idea that moving dislocations are the most important carriers of H_2 to critical sites. As is well known from the dynamic strain ageing phenomenon, the process needs a critical dislocation velocity (hence the strain rate), a certain critical temperature range (for the maintenance of a moving hydrogen atmosphere) and a viable dumping mechanism at critical sites (e.g. grain boundaries, voids, precipitate particles, inclusions etc). Both theoretical considerations and experimental evidence point towards the viability of such a mechanism (at temperatures where purely diffusion controlled transport may be unimportant) and hence lend support to the contention that,

- embrittlement occurs only within a certain range of strain rate, temperature and concentration,
- strain rates less or greater than a critical value and temperatures too low or too high are not effective.

The close examination of fracture surfaces reveals that they are dimpled. The dimple size and distribution, along with the theoretical analysis showing that neither grain boundaries nor cracks could be effective critical sites in this type of embrittlement, have focussed attention on the role played by secondary phase particles in crack initiation. The particle size and distribution, interface coherency and/or incoherency and particle-matrix bond strength are assumed to play a decisive role.

13.2.3 Hydrogen attack

Steel exposed to high pressure hydrogen at temperatures between 300 and 500°C appears to be unaffected for days or months, and then in a matter of hours it loses much of its ductility and strength. The high diffusivity of hydrogen allows it to move through the micro-structure and react with iron carbides, either directly or through carbon in solution. The reaction products are mainly Fe and CH_4, and since the rather large CH_4 molecule cannot diffuse easily it tends to accumulate at the grain boundaries (heterogeneous nucleation) and form bubbles.

The possible reactions and steps for the continued growth of bubbles by carbide solution are:

a) $Fe_3C \rightarrow 3Fe + C$ (in solution)

b) Movement of C to bubbles

c) $C + 2H_2 \rightarrow CH_4$

d) Movement of Fe atoms from bubbles

Some detailed analysis of methane bubble nucleation and growth has resulted in the Nelson diagram, which is a plot of temperature vs pressure for various incubation periods. It has been suggested that the incubation period is associated with the attainment of a critical size of methane filled voids. Below the critical size, the surface tension of the void resists the methane pressure and growth is slow, and perhaps reversible. However, growth proceeds rapidly after attainment of the critical size. Deterioration of the mechanical properties ensues.

Steels with alloying elements such as Cr and Mo show enhanced resistance to hydrogen attack. These elements are strong carbide formers; however, it is not fully clear by what mechanisms the observed beneficial effect imparted by these solutes is brought about. Is it due to the resistance to H_2+ carbide → methane reaction or is it due to the effective scavenging of carbon from solution? For Fe_3C, as pointed out earlier, $Fe_3C + 2H_2 \rightarrow CH_4 + Fe$ is the reaction preferred.

13.2.4 Hydrogen environment embrittlement

This type of embrittlement occurs as long as the material is exposed to hydrogen environment and terminates as soon as the hydrogen atmosphere is removed. Embrittlement due to previously absorbed hydrogen (as described earlier) may add to or synergetically interact with hydrogen environment embrittlement. A variety of alloys have been found to be susceptible to this effect which manifests itself as:

- Blistering, surface cracking, and loss in ductility of a material in tension at high pressure and temperature.
- Stress-corrosion* if hydrogen evolution occurs due to corrosion or electrolytic processes.
- Sub-critical crack growth which occurs if such cracks are present at the surface under stress.
- Crack growth rates for given cyclic or sustained stress intensities that are faster in hydrogen than in inert environments.
- A creep rupture life of many Ni and Fe based alloys that may be decreased in hydrogen environment.

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* Stress-corrosion is discussed later on under a separate heading.

Hydrogen induced cracking and blistering:

The environmental embrittlement occurs mainly at the surface. The embrittled surface may be the immediate surface or a surface layer of some finite but limited thickness. The metal surface cannot undergo plastic deformation under tension to the same degree in hydrogen as it can in air or inert environments. Thus when a susceptible metal is stressed under tension in hydrogen to some critical amount of plastic deformation, the surface fractures (i.e. surface cracks form) even at ambient temperatures. It is not yet established whether hydrogen environment embrittlement is a surface effect involving only the dissociation and adsorption of the hydrogen into a surface layer of small but finite thickness. The lack of incubation period and the rate at which this type of embrittlement manifests itself suggest that volume diffusion of hydrogen in the metal does not play a significant role. The process is rapid and it is very sensitive to the strain rate or crack propagation rate, almost vanishing at high strain or crack propagation rates as evidenced by the fact that the final failure in a tensile specimen pulled in hydrogen is a ductile overload failure, which is unaffected by the hydrogen environment.

The above suggests that some fast rate mechanism of H_2 transfer is operative at the surface even at lower temperatures and that a supersaturated layer immediately beneath the surface contains some kind of flaw where hydrogen gas precipitation may occur. A dislocation mechanism of hydrogen transfer and the presence of internal flaws near the surface may fulfill these requirements.

Internal flaws are generally cracks rather than voids. They can form in materials of widely varying strength levels, alloy contents and heat treatments and have been observed in zone-refined Fe, high strength steels, Ni base alloys, austenitic stainless steels, Al alloys, Ti alloys and others.

When these flaws are located near, and most effectively parallel to external surfaces, surface blistering is often observed. Blisters are believed to be formed by a stress relief mechanism, related to the build-up of internal pressure in near-surface flaws. Intense, highly localized slip produces large surface offsets which may cause microscopic blisters. It has often been found that the blisters in the early stages of their development may be crystalline in nature.

The most comprehensive study of cracking behaviour has been carried out on Fe and steels. The study indicates that cracking is a strong and reasonably predictable function of alloy elements, grain size, texture and heat treatment.

It appears that in most iron alloys, the crack path is controlled by partitioning of carbon between the grain boundary and the lattice. The study of crack path transition from intergranular to transgranular shows that the process is thermally activated with the activation energy near that for carbon diffusion in Fe. It is believed that as carbon moves towards grain boundaries, the tendency to transgranular cracking increases. The addition of a third element may alter or modify the crack path from transgranular to intergranular or vice versa, depending upon how the activity of C and H_2 is influenced by the solute atoms.

There is much evidence showing that preferential segregation of alloying elements (e.g. Sn, Sb) can promote intergranular cracking in the hydrogen environment. This would indicate that the recombination of hydrogen to form molecular hydrogen is somehow suppressed. However, a real assesement of this role of solute atoms cannot be made until the valence state of these elements in the metal is known, since this determines whether or not a metalloid acts as a hydrogen poison or promotor of recombination. The effect of heat treatments on hydrogen induced cracking lends to the speculation that crack paths can be presensitized so that different types of cracking can occur.

Alloying elements can also be used to control hydrogen induced cracking; Ti is an example which appears to act as a hydrogen trap in Fe. The favourable trapping ability, which manifests itself as a decrease in hydrogen diffusivity, appears to diminish when Ti combines with other solutes such as C, N and O. Al, when present as an Fe-Al solid solution, may suppress cracking. Permeation studies on Al alloys show that the hydrogen diffusion is much reduced by comparison with pure Fe. This may result from either a decreasing diffusivity or the trapping effect of the Kirkendall voids associated with the aluminizing process.

The role played by solute atoms, as observed in various studies, leads to the following general conclusions:

- Solute trapping of hydrogen (directly or indirectly) may reduce hydrogen cracking.
- A combination of solute elements that predispose a particular crack path or establish a sharp texture through work annealing cycles may also reduce the cracking incidence.

Environmental parameters:

- Plane strain fracture toughness (K_{IC}), sustained load crack growth and the threshold stress intensity for sustained crack-growth, cyclic load crack growth and surface cracking propensity are all affected adversely and increasingly with increasing H_2 pressure.
- Embrittlement occurs over a wide range of temperatures, from cryogenic to at least ~ 870°C, but it is most severe in the vicinity of room temperature. Thus, high pressure at around room temperature appears to be most critical.
- The purity of the H_2 gas is important. O_2 in H_2 has been found to be beneficial. Similarly small amounts of SO_2 and CS_2 have been found to be effective in stopping running cracks; the inhibiting effect of CO_2 is only moderate, and N_2 and argon have no noticeable effect.

13.2.5 Chemical reactions

Metals and alloys which form a hydride offer another mode of hydrogen embrittlement. It is generally believed that cracks are initiated at hard and brittle hydride particles, as is the case in Zr and Ti alloys. The morphology of the hydride particles in Ti and Zr alloys is such that it provides reason to believe that they serve as stress concentrators.

Any real understanding of the hydride induced embrittlement must also include the role of the relatively soft matrix in which hydrides are imbedded. A mechanism has to be provided by which a crack at a fractured hydride particle will grow into the soft matrix under the applied stress and ultimately bring about the fissuring and failure of the metal-hydride composite.

Given an initial crack at a hydride particle, at any instant the equilibrium hydrogen concentration at the crack tip will be higher than the average lattice concentration. The impoverished lattice ahead of the crack will be replenished by hydrides which dissolve gradually because of a finite solution pressure. In this way a high supersaturation of H_2 at the crack tip may be achieved at the cost of hydrides, and a new hydride particle may be precipiated at the crack tip which eventually fractures under the applied stress resulting in crack prolongation. The process may repeat many times to cause ultimate fissure. The facility with which such processes may occur depends upon a suitable combination of temperature, stress concentration factors, strain rate and volume fraction of the hydride particles and perhaps even the morphology of the particles.

13.2.6 Solid solution hardening embrittlement

In certain transition metals such as V, Nb and Ta and their alloys, hydrogen embrittlement manifests itself by an overall reduction in ductility due to matrix hardening from hydrogen in solution. If saturated with hydrogen, an additional hardening is observed due to the precipitation of hydrogen atoms in small clusters or even hydride particles. The former is favoured by the presence of alloying atoms where the interaction between hydrogen and the solute is attractive.

The two separate hardening mechanisms mentioned above show strength maxima at two different temperatures (or ranges of temperatures), which coincide with the observed ductility minima.

In the presence of stress, stress induced precipitation of hydride may occur even at temperatures where ordinarily hydrogen is expected to be in solution.

13.2.7 Stress corrosion embrittlement

Hydrogen induced stress corrosion embrittlement belongs to the category of hydrogen environment embrittlement, but it is treated separately because hydrogen production and its transport to decohesion enclaves occur in a corrosive environment.

In the presence of a chemically active environment, it is generally believed that a protective surface layer is formed by various mechanisms and that the metal-hydrogen contact depends critically upon the frequency with which film rupture and repair is occurring. Hydrogen dissociation and adsorption is a fast process (10^{-6} s) and hence a repair time much shorter than 10^{-6} s is needed to prohibit H_2 adsorption. In aqueous environments anodic dissolution is expected to occur efficiently for the resharpening of crack tips blunted by plastic deformation, and in most cases a continuous supply of hydrogen exists near the crack tip.

A large quantity of hydrogen generated at a very high fugacity in or at the crack is expected to be adsorbed and absorbed at the exposed surfaces. The amount absorbed is much in excess of the solubility limit and is often considered to form hydrides or cracks. Dislocation transport (because of applied stress) is expected to carry the hydrogen further where the hydrogen concentration in the hydrostatic stress field of the crack tip is slowly built up. From this stage, the crack progagation may continue in the manner described earlier in 13.2.4.

The initial crack at the surface may start at the grain-boundary (from electro-chemical effects due to grain boundary segregation) or at a corrosion pit inside a grain (from segregation effects on film dissolution) but its propagation inside the material is not expected to have any memory of its origin. Thus, depending upon the heat-treatment, the nature of solute elements and their interaction with hydrogen atoms, grain boundary segregations, internal flaws etc, an initially intergranular crack may branch into a transgranular crack or vice versa.

Ferritic and austenitic steels, and alloys with Al, Ni and Ti, have been found to crack and fail in aqueous solution in the above manner. Certain passivating agents have the effect of inhibiting stress-corrosion embrittlement by hydrogen. These agents generally possess a net dipole moment forming a double electrical layer at the surface of the metal. The electrical interaction between the dipolar molecules and the surface decreases the net surface accumulation of hydrogen by adsorption. Oxide layers are not always an effective inhibitor. Certain oxides may even adsorb considerable quantities of H_2.

13.3 Evaluation of materials

As seen from the above, hydrogen embrittlement of structural materials may occur in a wide range of materials under a wide variety of conditions and in many different ways. Because of the aggravated crack sensitivity of the materials in hydrogen, even a sound material with surface irregularities may cause hydrogen assault. Methods of joining metals, welding in particular, may prove to be specially vulnerable, and because the weakest link in a chain determines the chain strength, suitable welding pratices and separate testing of welds are vital.

Economic considerations and various demands made on component materials at each stage from production to transmission and utilization necessitate the selection of materials with a wide range of composition, structure, strength and chemical and physical properties. There is no simple way to prescribe a simple criterion in material evaluation and selection. Nevertheless, certain patterns emerge:

- Area reduction (RA) and true fracture strain (E_f) give a better measure of material ductility than engineering, % elongation and % tensile strain

  $$RA = \frac{Ao - Af}{Ao} \quad ; \text{ where } Ao = \text{initial area}, \; Af = \text{fracture area}$$

  $$E_f = \frac{1}{1 - RA}$$

- Delayed failure and fracture mechanical K factors for crack resistance (initiation plus growth) must be determined and crack velocity/stress intensity tests must be performed on all materials. Here, attention must be given to specimen size. Crack propagation susceptibility in thicker samples is generally greater than in a corresponding thin-walled specimen.

- Creep resistance in hydrogen atomosphere must be established.

- Increased contents of Mn and C for strength purposes increase the susceptibility of the material to hydrogen embrittlement, specially under cathodic polarization. Cr has also been found to be deleterious. Si and Ti additions appear to be beneficial. On the other hand Ni, Co and perhaps Mo appear to be neutral.

- Tempered martensitic (bainitic) structure provides good resistance to hydrogen embrittlement. However, Mn rich bands in pearlitic steels may fail easily along the band.

- For austenitic stainless steels, stacking fault energy (SFE) becomes important. A steel with higher SFE has better crack propagation resistance and hence an Fe-Cr-Ni composition should be chosen judiciously (see Figure 13-1).

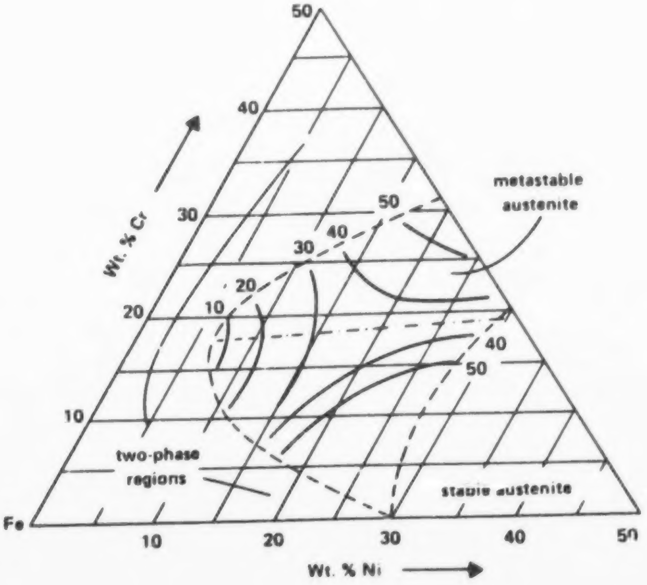

Figure 13-1

Approximate iso-SFE contours in the iron-rich corner of the Fe-Ni-Cr diagram.

- There is no definite correlation between strength and susceptibility. Microstructure, compositon and heat treatments are of determinative importance.

- Structural changes occurring subsequent to welding operations may lead to undesirable martensitic structures (hard spots) after cooling. Steels of particular compositions may develop similar "hard spots" due to precipitation hardening. Thus depending upon the steel composition (see Figure 13-2) post annealing treatments (with judicious time-temperature parameters) may become necessary. Alternatively, welding methods should be modified.

- Very pure hydrogen is more deleterious than relatively impure. Therefore, injection of certain suitable inhibitors (e.g. O_2, CO_2, SO_2) may reduce the embrittlement problem. This should be particularly useful in transmission lines connected to a liquid H_2 reservoir.

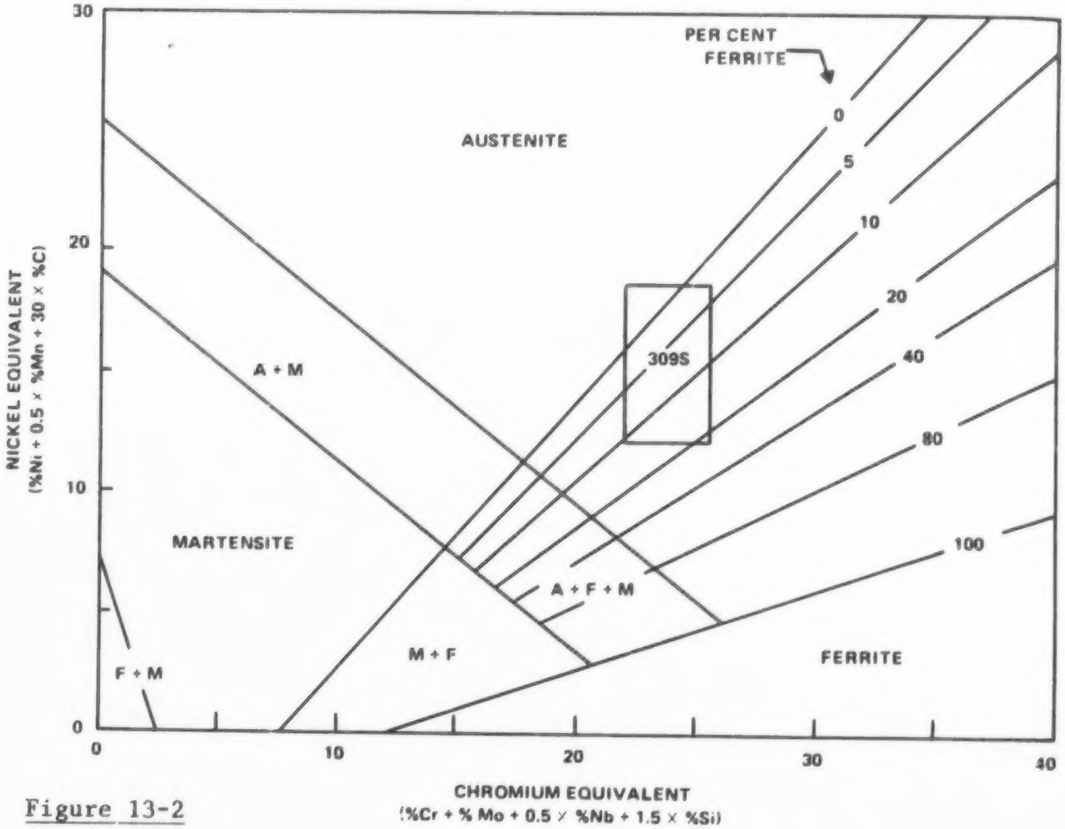

Figure 13-2

Microstructure diagram for as-welded stainless steels as a function of composition (Schäffler diagram), with commercial composition limits for 309S plotted to illustrate potential scatter in predictions, (7).

- Because hydrogen permeates very rapidly even at low pressures, "barrier-layers" of suitable choice should be considered. Brush painting of transmission lines with Pb-Sn alloys has been found to offer limited protection. Barrier layers of nonmetallic origin (eg. ceramics) should also be explored. Stainless steel sheaths applied to ferritic steels may offer a certain degree of protection.

- Effect of cyclical stress on the life expectancy of component in contact with hydrogen may not be very dramatic (specially for high alloy steels), but for low alloy steels this factor assumes some significance at high pressure loads (2 cycles per day). For metal hydride storage systems, however, stress cycles may be different (thermal stresses) and should accordingly be taken into account.

- For advanced applications, commercially available Ti and Ni base alloys may be used with certain compositional and structural modifications. In Ti alloy β or $\alpha + \beta$ phase resists hydrogen embrittlement which could be further adjusted by additions of Mo, V, Nb and Ta in small quantities.

  α-Ti and alloying elements which stabilize the α-phase (e.g. Mn, Co and Cr) are not suitable for hydrogen applications. Pure Ni is susceptible to H_2 embrittlement, but judicious additions of Fe, Cr and Cu ameliorate the damage to a certain degree provided the level of addition produces no second-phase δ particles.

- Al, Cu and Monel (Be-Cu alloy) are not susceptible to high pressure hydrogen embrittlement. However, Al and Cu are not very strong even in their alloyed forms. Some limited applications of Al alloys are possible where reduced weight or atmospheric corrosion resistance may become the deciding factor.

13.4 Technical data

Some experimental data on the susceptibility of various classes of materials to various types of hydrogen damage discussed in 13-2 (see Table 13-3) are presented below.

13.4.1 High temperature components

Hydrogen production methods at elevated temperature need materials with high "Ultimate Tensile Strength" (UTS), high creep strength and resistance to hydrogen attack. A Nelson diagram characterizing hydrogen attack in some alloy steels is shown in Figure 13-3. Figure 13-4 shows the creep characteristics of A-286 stainless steels in a hydrogen atomosphere. Nelson diagrams for stainless steel are not available but the same method may probably be extended to the hydrogen attack of carbides in austenitic stainless steels and Ni base alloys. Temperature dependences of UTS and creep rupture for certain high strength steels are shown in Figures 13-5 and 13-6, respectively, demonstrating rather clearly the reduced strength and creep-rupture life even in the absence of hydrogen.

Table 13-3

Metals and alloys embrittled by hydrogen (8).

Hydrogen environment embrittlement*	Internal reversible hydrogen embrittlement*	Hydrogen reaction embrittlement*
High strength steels 18Ni Maraging 410, 440C, 430F, 403, 431 H-11, 4140, 1042 (Q&T) Fe-9Ni-4Co, 17-7PH Nickel and nickel alloys Electroformed Ni Nickel 200, 270, 301 Inconel 625, 700, 706, 718, X Rene 41, Hastelloy X Udimet 700, Waspaloy MAR M-200DS, IN 100 Low strenght steels Armco iron, CK22, CK45, 1020 1042 Nor, HY-80, HY-100 A-302, A-515, A-517, A-533B 1146a, HY-130, SA105 Titanium alloys Ti-6Al-4V, Ti-5Al-2.5Sn Molybdenum-TZM Cobalt alloys HS-188, L-605, S-816 Metastable stainless steels 304L, 305, 310, 309S K-Monel Be-Cu alloy 25 Pure titanium Stable stainless steels 316, 321, 347, A-286 Armco 2-6-9, 22-13-5 Copper alloys, OFCH Cu TD-Ni, TD-NiCr Magnesium alloys HM21A Aluminium alloys 1100, 2219, 6061, 7039,	High strength steels 4340, 4140, H-11 17-4 PH, AM 355 18Ni Maraging E8740, 17-7PH Exp. Fe-Ni-Cr alloys Exp. Fe-Cu alloys Ti, Zr, V, Nb, Ta Cr, Mo, W, Co, Ni Pt, Cu, Au, Al, Mg and/or some of their alloys Metastable stainless steels 304L, 301 K-Monel High strength nickel alloys Inconel 718 Rene 41 Waspaloy Hastelloy X Stable austenitic steels 316, A-286, U-212, 21-6-9	Hydrides (MH_x) H reacts with matrix Ti, Zr, Hf, V, Nb, Ta Mn, Ni, Pd, U, Pu, Th Rare earths Alkalies Alkaline earths H reacts with element MgZr, MgTh alloys High pressure gas bubbles H reacts with itself (H_2) Steels, OFHC Cu Ni, Al, Mg, Be H reacts with foreign element in matrix CH_4 in low alloy steels, Ni alloys, H_2O in welded steels, Cu, Ni, Ag, NH_3 in molybdenum

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* Listed in approximate order of decreasing susceptibility at room temperature.

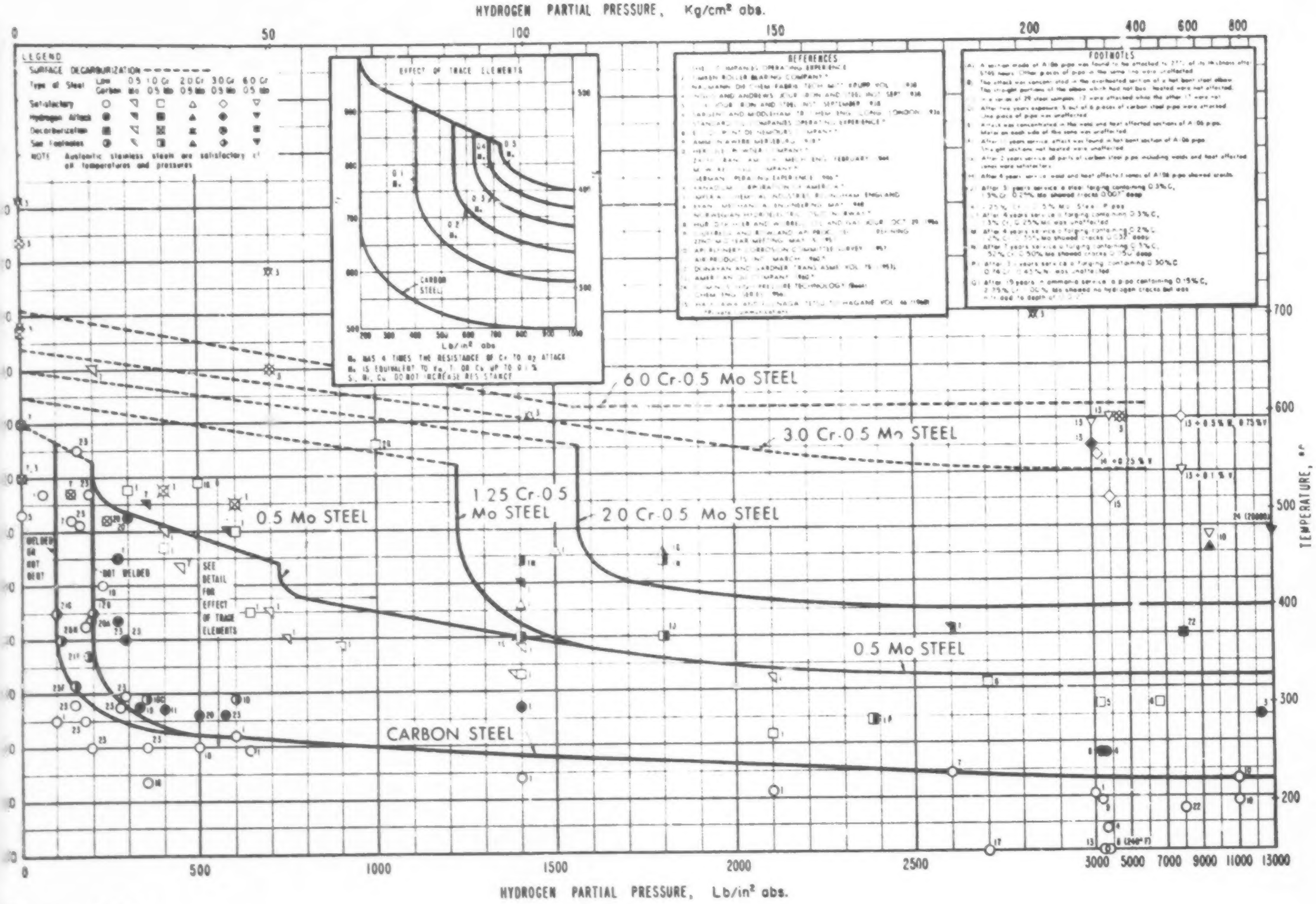


Figure 13-3

Operating limits for steels in hydrogen service, (9).

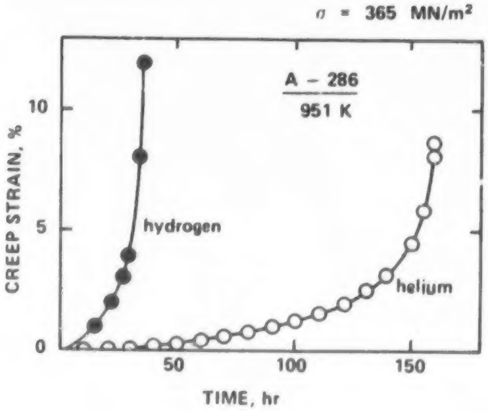


Figure 13-4

Creep rupture for A-286 stainless steel at 951 K under constant stress of 365 MN/m^2, in 34.5 MPa pressure of helium or hydrogen, (7).

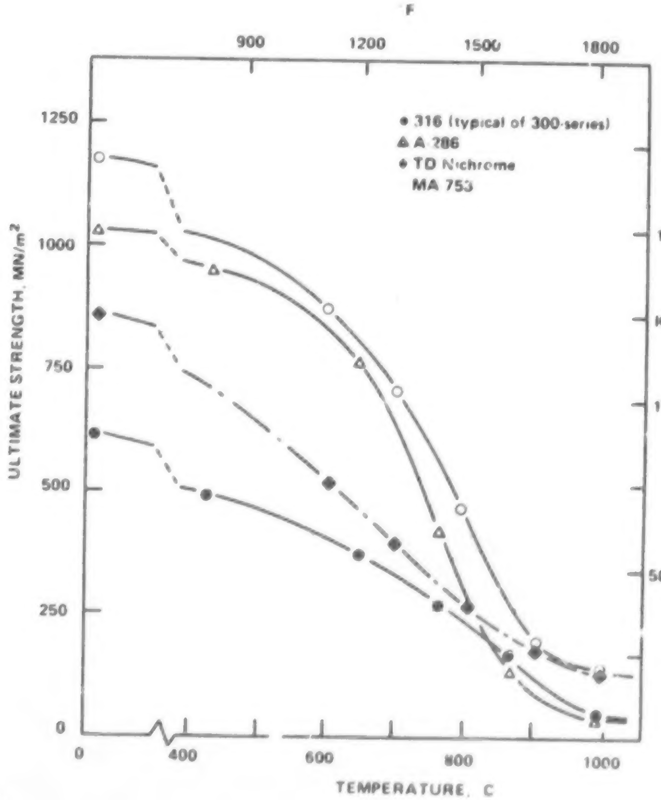
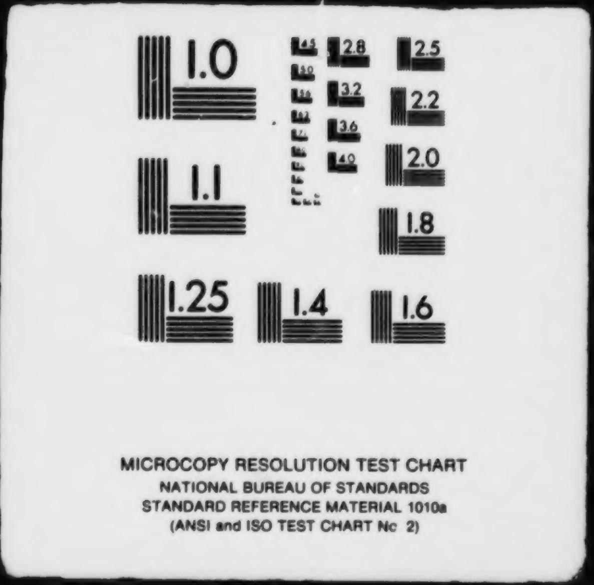


Figure 13-5

Ultimate tensile strength as a function of temperature for stainless steels (316 and A-286) and dispersion-strengthened nickel (TD nichrome or [illegible] and MA 753), (7).

5 OF 5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NATIONAL BUREAU OF STANDARDS
STANDARD REFERENCE MATERIAL 1010a
(ANSI and ISO TEST CHART No 2)

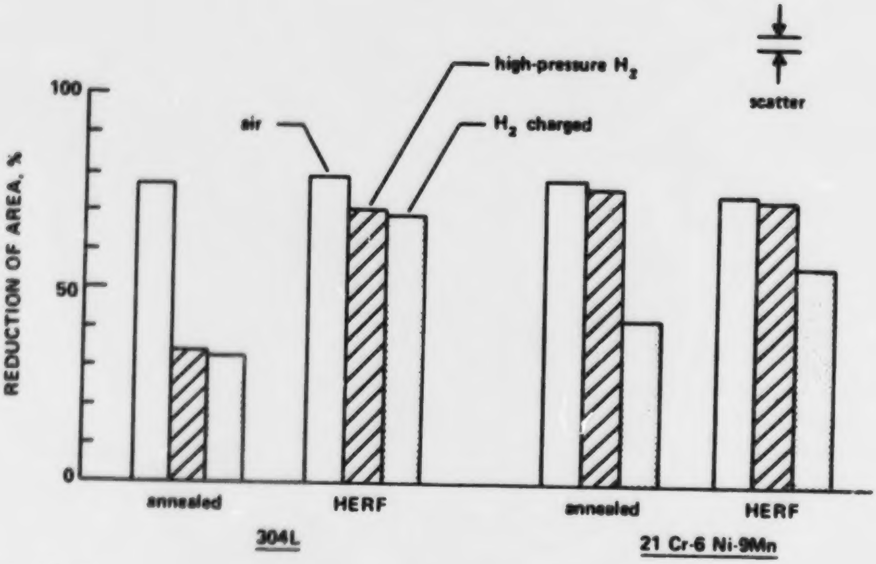

Figure 13-8

Ductility of 304L and 21Cr-6Ni-9Mn stainless steels, tested in air, in 69 MPa hydrogen gas, or after hydrogen charging to supersaturation. Effect of thermomechanical history (HERF) is shown, (7).

HERF = high energy rate forming.

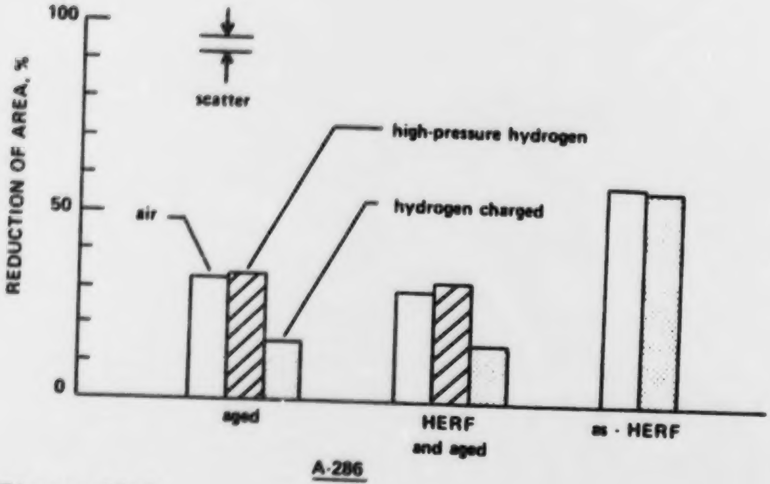

Figure 13-9

Behaviour of commercial A-286 with various histories for tests in 69 MPa hydrogen gas and after hydrogen charging to supersaturation from the gas phase, (7).

HERF = high energy rate forming.

Table 13-4

Typical compostions of austenitic stainless steels (wt %), (7).

	Cr	Ni	Mn	C	N	Si	Mo	Other
Standard grades								
304	19.0	10.0	1.5	0.06	-	0.5	-	
304L	19.0	10.0	1.5	0.03	-	0.5	-	
309	23.0	14.0	1.5	0.20	-	0.5	-	
309S	23.0	14.0	1.5	0.06	-	0.5	-	
310	25.0	20.0	1.5	0.20	-	1.0	-	
316	17.0	12.0	1.5	0.08	-	0.5	3.0	
321	18.0	11.0	1.5	0.06	-	0.5	-	Ti: 5XC
347	18.0	11.0	1.5	0.06	-	0.5	-	Nb: 10XC
Special grades								
18Cr-25Mn	18.0	-	15.0	0.04	0.5	0.5	-	
21Cr-6Ni-9Mn	20.0	7.0	9.0	0.04	0.3	0.5	-	
22Cr-13Ni-5Mn	22.0	12.5	5.0	0.05	0.3	0.5	2.0	
Age-hardening alloys								
A-286	15.0	25.0	1.5	0.05	-	0.6	1.2	2.25 Ti, 0.2 Al
V-57	15.0	26.0	0.3	0.05	-	0.6	1.3	3.0 Ti, 0.3 Al
"Alloy 8"	14.5	30.0	0.1	0.02	-	0.2	1.2	2.1 Ti, 0.25 Al

13.4.2 Pressure vessels and pipelines

In a large-scale hydrogen energy delivery system, the tonnage of materials required for storage pressure vessels and distribution lines is expected to be large. Economic considerations are therefore vital. Tables 13-5 and 13-6 give some typical compositions of steels considered for pipeline and pressure vessel constructions, respectively. Table 13-7 presents their mechanical properties. As mentioned earlier, the degree of embrittlement increases with increasing hydrogen pressure and with the increasing strength of the material. These facts are dramatized by Figures 13-10 and 13-11, respectively.

The deleterious effect of hydrogen on notch tensile strength and cyclic crack growth in some pressure vessel and pipeline quality steels is presented in Figures 13-12 and 13-13. Similarly Figures 13-14a and b show the strain rate and the temperature dependence of ductility in a pipeline quality steel in air and hydrogen atmosphere. The deleterious effect of H_2 is quite clear.

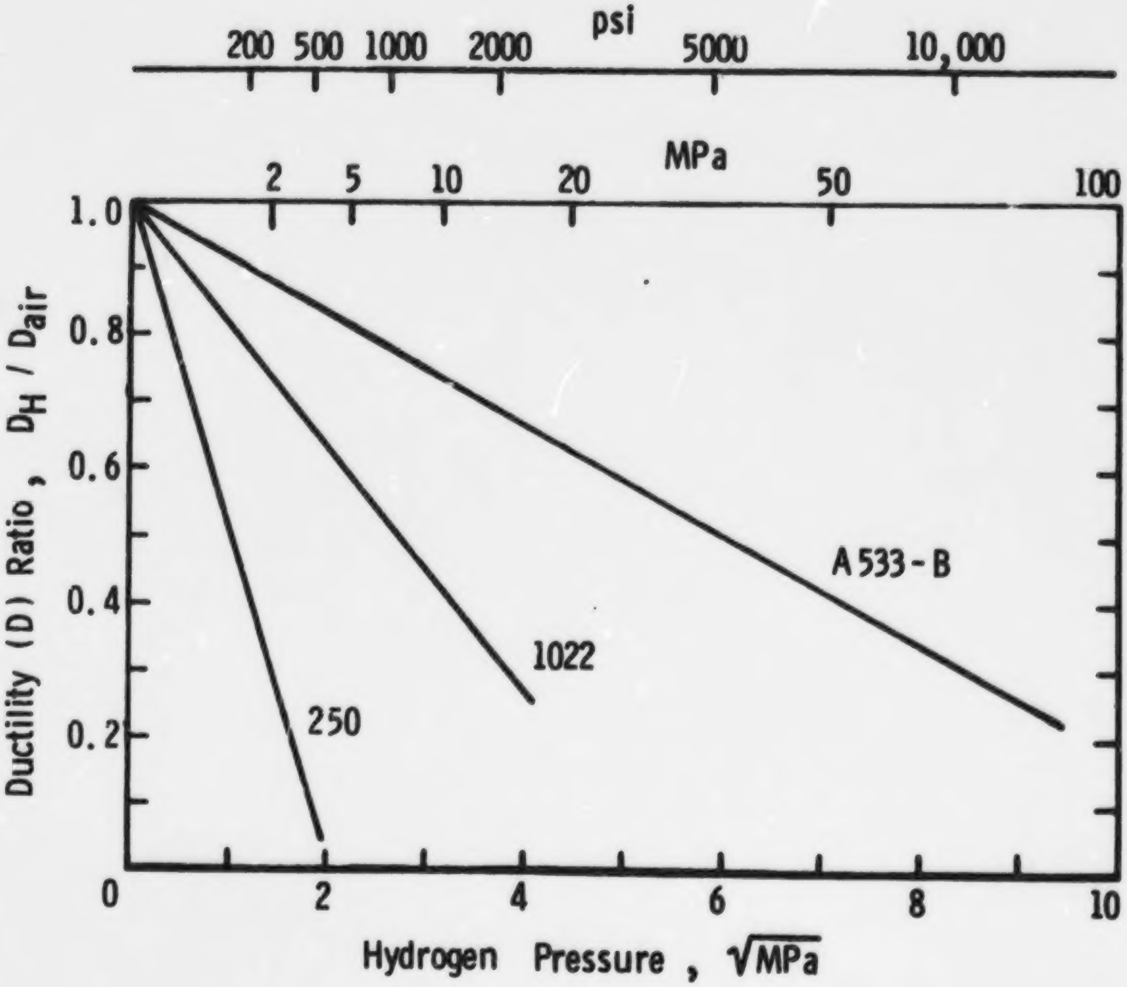

Figure 13-10

Ductility ratio of three steels as a function of the hydrogen gas pressure in which the test was conducted. 250 maraging steel, yield strength 1725 MN/m^2; 1022 high-Mn carbon steel, ultimate strength 500 MN/m^2; A533-B, see Tables 13-6 and 13-7, (7).

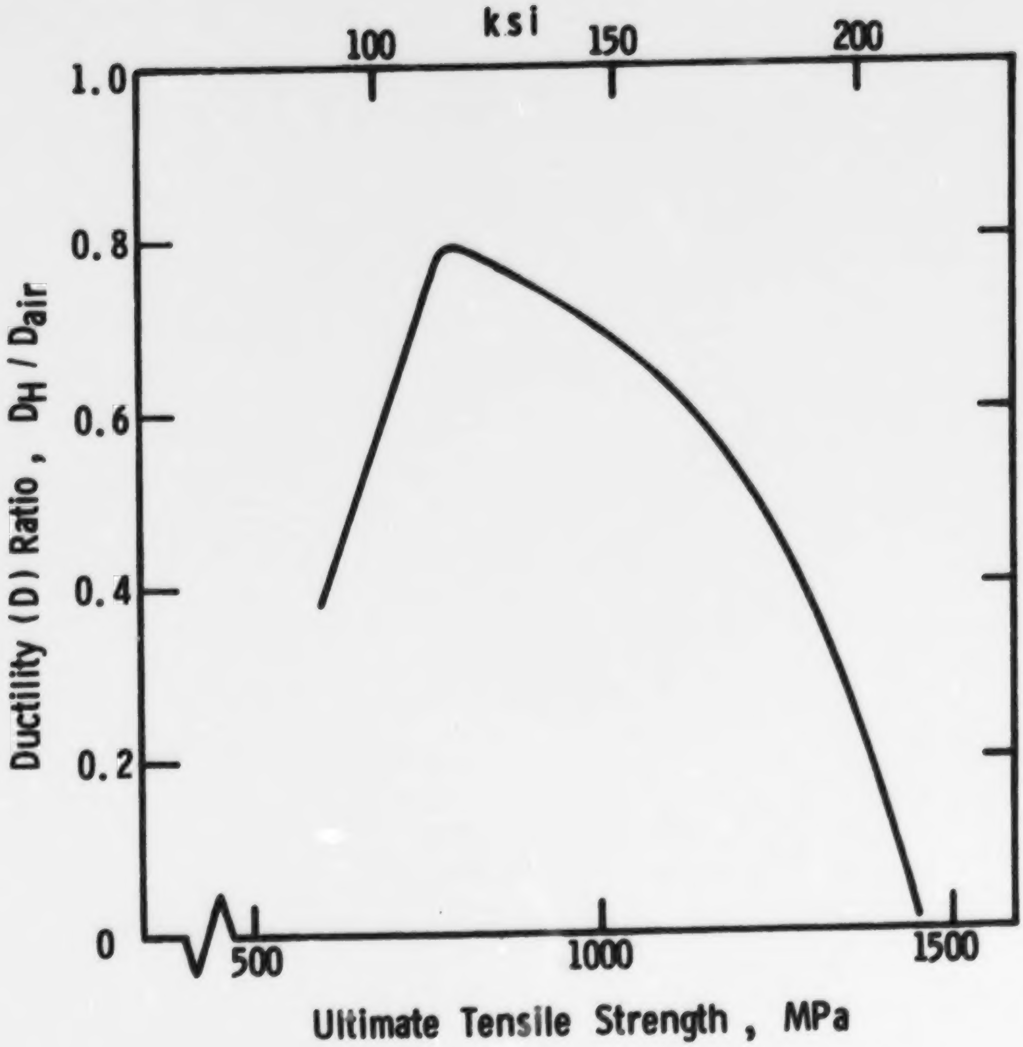

Figure 13-11

Ductility ratio (hydrogen to air) of a 3.3 % Cr - 0.4 % Mo - 0.26 % C steel, containing 3.6 wt ppm H, as a function of ultimate tensile strength, (10).

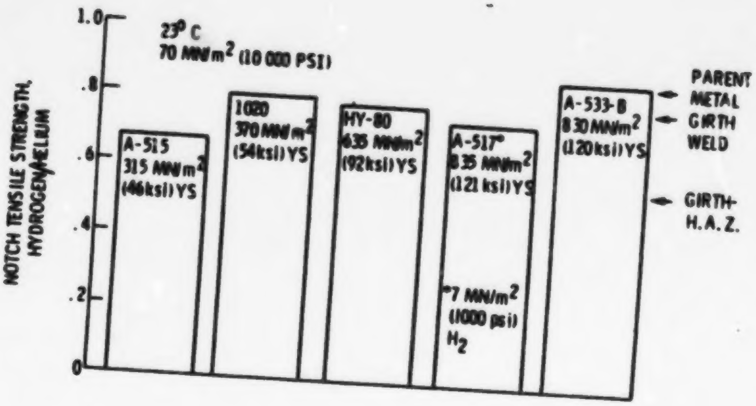

Figure 13-12

Effect of hydrogen (99.999 %) on notch tensile strength of pipeline and pressure vessel steels, (8).

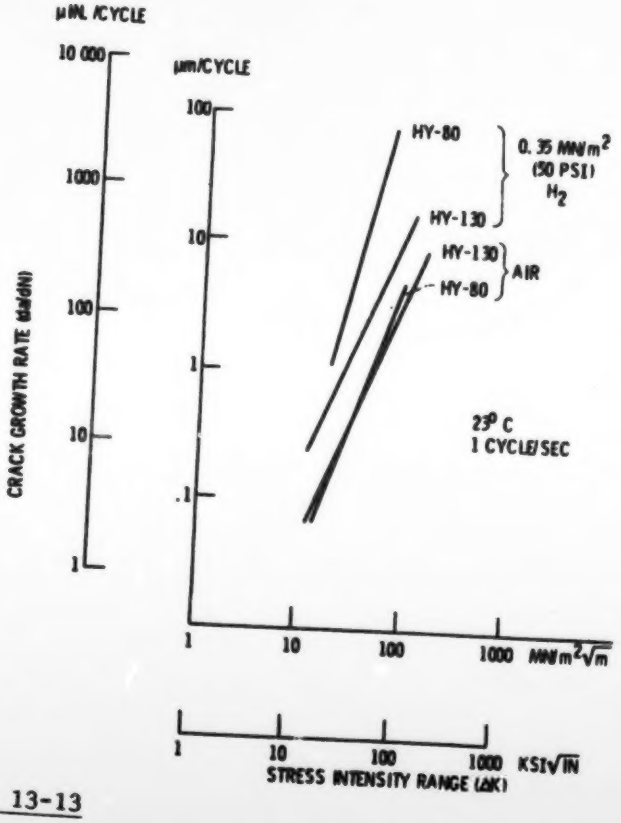

Figure 13-13

Cyclic crack growth of pressure vessel steels in hydrogen (99.9 %) and in air, (8).

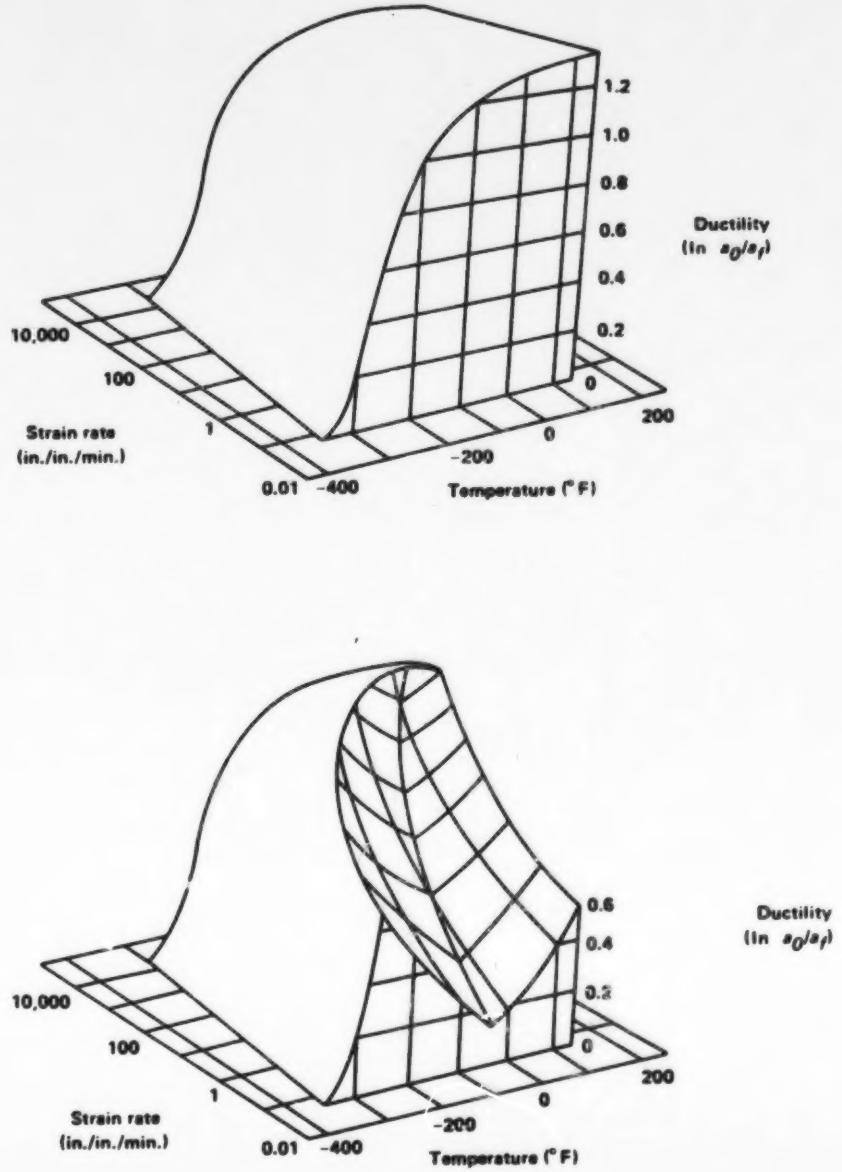

Figure 13-14a, b

Ductility, expressed as E_f of spheroidized 1020 steel, as a function of strain rate and temperature. Hydrogen-free specimens (top); hydrogen-charged specimens (bottom), (7).

Table 13-5

Composition of typical linepipe steels (wt %), (10).

Steel	C	Mn	Si	P**	S**	V	Ti	Nb
ASTM A53-B	0.30	1.20	-	0.05	0.06	-	-	-
ASMT A106-B	0.30*	0.29-1.06	0.10 min.	0.05	0.06	-	-	-
API 5L-B	0.27*	1.15*	-	0.04	0.05	-	-	-
API 5L-X42	0.28*	1.25*	-	0.04	0.05	-	-	-
API 5L-X52	0.29*	1.35*	-	0.04	0.05	-	-	-
API 5L-X60	0.26*	1.35*	-	0.04	0.05	0.02	0.03	0.005
API 5L-X70≠	0.23*	1.60*	-	0.04	0.05	-	-	-

* Maximum.

** Approximate maximum.

≠ Tentative grade.

Table 13-6

Composition of typical pressure vessel steels (wt %), (10).

Steel*	C	Mn	Ni	Mo	Other
Type 1146a (A.O. Smith)	0.22	1.1-1.5	0.4-0.7	-	0.15 V
ASTM A302-B	0.20	1.15-1.50	-	0.45-0.60	-
ASTM A372-IV	0.40-0.50	1.40-1.80	-	0.15-0.25	-
ASTM A517-F	0.10-0.20	0.6-1.0	0.7-1.0	0.40-0.60	0.05 V 0.15-0.50 Cu, 0.40-0.65 Cr
ASTM A533-B**	0.25	1.15-1.50	0.40-0.70	0.45-0.60	-

* Also typically contain 0.05 - 0.30 Si, 0.04 S and 0.035 P.

** Previously designated A302-B (Ni Modified).

Table 13-7

Example of mechanical properties of steels, (10).

Steel*	Yield	Strength	Ultimate yield	Ultimate strength	Elongation in 25 mm, %
	Ksi	MN/m^2	Ksi	MN/m^2	
A53-B	35	240	60	415	-
A106-B	35	240	60	415	22
5L-B	35	240	60	415	25
5L-X52	52	360	66	455	20
5L-X60	60	415	75	515	21
5L-X70	70	485	82	565	20
1146a	80	550	105	725	22
A302-B	50	345	100	690	18
A372-IV	65	450	105	725	15
A517-F	100	690	125	860	16
A533-B	70	485	100	690	16

* See Tables 13-5 and 13-6.

13.4.3 Metal hydride containers

Metal hydrides and molecular sieves as media for solid state hydrogen storage are attractive for specialized applications and are avidly researched. However, long term operational experience of the container material integrity under the expected service conditions is lacking. The problem areas can be defined, however, and should be kept in mind in all considerations of container design and material selection. The points to be considered are as follows:

- Many metallic hydrides, e.g. MgH_2, may heat up to temperatures in excess of 600°C during charging. The structural material may be subject to hydrogen attack as defined in 13-2. For such hydride systems, the material problem overlaps with those considered under 13.4.1.

- Certain metals (M) in applied hydride systems form oxides which are more stable than those present on the surface of structural materials (M^1). If so, a reaction of the type

$$2MH + M^1O \rightarrow M_2O + M^1 + 2H$$

may occur during the heat-up for discharge. There is evidence that hydrogen liberated at the metal surface enters the metal rather than combining to form a molecule (H_2), thereby conditioning the structural material for a probable delayed failure if sufficient stresses are introduced during the heating and cooling cycles.

- Life expectancy of the container material may be adversely affected due to cyclical thermal stresses induced from the repeated charging and discharging of the unit during its life span, thereby necessitating avoidance of low alloy steels as container material.

13.4.4 Liquid hydrogen systems

The principal new material problems encountered in LH_2 systems are due to the low temperatures required, $\leq$ 21 K. Failure of components may arise for the following reasons:

- Metallic junctions of incompatible electro-galvanic behaviour leading to hydrogen aided stress corrosion.
- Austenite to martensite transformation in stainless steel components at cryogenic temperatures, and low frequency stress cycling due to periodic warm-ups.
- Hydrogen intake resulting in solid solution and hydride particle embrittlement in case of extended warm-up periods, if for some special reasons refractory materials, such as V, Nb, Ta and even Ni, are used in certain parts of the total cryogenic system.

13.4.5 Material problems with electrolytic cells

Hitherto, there are no reported failures of the electrolyser container materials. The reason may lie in the fact that the electrolytic production of hydrogen is mainly applied on a small scale and that the equipment is operated at low temperatures and pressures. The trend has been towards an updating of the quality and the efficiency of internal components, such as electrode materials, catalytic coating for efficient hydrogen production, separators, gasketing and insulating materials, with the aim to achieve higher operating temperatures (200°C) and working pressure (3 MPa). The present generation of cells are run at about 60 - 70°C.

In more advanced types of electrolysers, still in the development stage, solid electrolytes of acid polymer or oxide type are expected to replace the alkaline solutions of the current generation of electrolysers. Temperatures of 150 - 200°C and 800 - 1000°C are theoretically achievable in these advanced systems.

These trends, where increasingly higher cell temperatures and pressures are to be used for achieving lower and lower cell voltages with higher and higher current density, are bound to result in container and internal material failures due to hydrogen embrittlement by the various mechanisms discussed previously, in particular by induced stress corrosion crack propagation. At present, however, the major part of the research is limited to component design, the selection and application of catalytic coatings for efficient hydrogen evolution, the choice of strong and temperatur resistant seals, gaskets, separators, connectors etc.

It is to be expected that along with the commissioning of demonstration units of advanced electrolysers, parallel research will be initiated for container materials, ceramic components and various other inorganic compounds.

13.5 Conclusions

In spite of proposed plans for the underground storage of hydrogen in depleted gas fields or aquifers, it is anticipated that metallic pressure vessels or LH_2 containers will continue to play an important role for the large-scale and/or intermittent storage of hydrogen in the foreseeable future. Similarly, metallic pipelines are not expected to be displaced by fibre-reinforced polymers for some time to come. Research on metallic materials will probably continue in two different directions, namely the validation of existing materials and the standardization of test procedures on the one hand, and a search for new inexpensive materials, including protective coatings, on the other.

Existing pipelines used for natural gas distribution may not be suitable for H_2 gas distribution at the pressure envisaged. However, if pressure requirements were somewhat lowered and some revalidation of the soundness of the weld joints were forthcoming, it is not inconceivable that they could be commissioned for hydrogen service with a fair degree of security. The injection of suitable inhibitors might contribute to a further increased degree of confidence. The non-failure of most of the existing hydrogen pipelines (Table 13-8) after long service has been mainly attributed to the low purity of the hydrogen, low pressures and the utilization of seamless tubes. Fundamental research to clarify experimental data will also continue. As a good example, there is the question of why certain alloying elements are beneficial even in small quantities whereas others are not, even if they belong to the same group in the periodic table. Could it be due to the interaction between the soluted ionic or anionic hydrogen with metallic ions? This and other controversial roles of hydrogen can not be dismissed on the grounds of structural or other metallurgical effects. In general, the following can be said about future research:

- For new alloy developments, more use should be made of Si and Ti and less of C and Mn as alloy strengtheners.
- Modified welding methods and practices have to be established.
- Internal barrier coating techniques and suitable gaseous inhibitors have to be found.
- Existing commercial alloys (with necessary modifications) may perhaps be adequate for hydrogen energy applications.

Table 13-8

Hydrogen pipeline experience, (8).

Location	Pipeline steel	Age year	Diameter cm	Length km	Hydrogen			Comments
					Purity	Pressure		
						MN/m^2	psi	
Air products - Texas	Converted natural gas line	6	10	8	99.5 %	6	800	No problems
Air products - Texas	New-schedule 40 steel	3	20	19	99.5 %	1.4	200	No problems
Germany	Seamless 1015 steel	up to 35	15-30	210	dirty*	1.8	260	No problems
NASA-KSC - Florida	316 stainelss steel	10	5	1.6	ultrapure**	42	6000	No problems
Linde	-	-	-	1.6-3	-	-	-	-
South Africa	-	-	-	80	-	-	-	-
Los Alamos	5Cr-Mo steel	8	3	6	ultrapure**	14	2000	Leaked in 3 yr, cracked in 4 yr, abandoned

* Purity unknown.

** Liquid boiloff.

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14. SAFETY AND PROTECTION

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14.1 Introduction

Hydrogen safety is an obvious priority need which must be faced if a broad use of hydrogen fuel is to be developed. Public perception and fears that may arise are generally attributed to the Hindenburg Zeppelin accident and to natural misgivings about any new and unknown fuel. This fear does not seem to be justified by the long and favourable record of hydrogen use in both industry and government programs. As "town gas", typically with a GH_2 content of 50 %, hydrogen has been in universal use and handled safely for about 100 years.

Hazards with hydrogen, as with any fuel, are related to the amount of energy stored and the method and rate at which this energy is released. They depend also on the nature of the use and the environment as well as on whether the measures are routine or extraordinary. The introduction of new technology such as the public use of hydrogen in transport always introduces new risks, but these tend to lessen as the technology becomes more established. However, hydrogen has some special properties, which will be more exhaustively discussed below, that require more careful handling procedures than for fuels in common use today. Leaks, spills and ignition are the main causes of fires and explosions. Other serious concerns include piping and pressure vessel failures, venting or exhaust system failures and improper purging procedures. Liquid hydrogen (LH_2) spills may result in air condensation associated with oxygen enrichment, thus enhancing the environmental combustion potential.

The disaster of the hydrogen-filled dirigible Hindenburg in 1937 caused tremendous publicity due to the scale and the unusualness of the accident, and to the directly audible presence of a radio reporter at the very moment of the occurrence. The airship, violating safety rules, approached its final destination, Lakehurst in New Jersey, through a thunderstorm and caught fire and burned while attempting to dock. The accident was evidently very serious with 58 passengers and crewmen killed, but it is seldom mentioned and nowadays almost forgotten that 65 people on board survived. In a similar accident with a less easily dispersible fuel like petrol or NG, it is hard to believe that anyone would have survived.

Hydrogen safety has been surveyed in several extensive reports (1 - 7) which contain long lists of references to the original investigations and experiments, covering the properties and phenomena of most concern. Some of the results are summarized below.

14.2 Safety-related properties

Hydrogen is the lightest of all the elements; the density of GH_2 is only 7 % of that of air. The gas is thus very buoyant and it diffuses rapidly away from the scene of a leak or a spill. Hydrogen is unreactive towards most metals at room temperature but it can be adsorbed in appreciable amounts by some metals, such as platinum and palladium. At higher temperatures, hydrogen combines directly with most of the lighter elements to form hydrides. The physical and chemical properties of GH_2 and LH_2 are more exhaustively discussed in Chapter 5.1. The most important safety-related parameters in air are collected below in Table 14-1 and compared to those of the competitive energy carriers NG and petrol. A systematic comparison with these alternatives is also made in the text.

Table 14-1

Properties of hydrogen, methane and petrol relevant to safety (in air).

Property	Hydrogen	Methane (NG)	Petrol
Heat of combustion, MJ/kg	142.5	55.3	48
Heat of vapourization, MJ/kg	0.45	0.51	~0.38
Diffusion coefficient, cm^2/s	0.63	0.2	0.08
Buoyant velocity, m/s	1.2-9	0.8-6	nonbuoyant
Ignition temperature, K	850	810	~530
Ignition energy, μJ	20	300	250
Flame temperature, K	2400	2190	2450
Flame velocity, m/s	2.75	0.37	<0.3
Emissivity of flame	0.1	1.0	~1.0
Quenching distance, cm	0.06	0.23	>0.25
Inflammability limits, %	4-75	5.3-15	1.5-7.6
Detonability limits, %	18-59	6.3-14	-
Vapourization rates of liquid, cm/min	2.5-5	0.05-0.5	0.005-0.02
Burning rates of liquid, cm/min	3.0-6.6	0.3-1.2	0.2-0.9
Energy of explosion, g TNT/g	~24	~11	~10

14.2.1 Ignition and flammability characteristics

The auto-ignition temperature of H_2-air mixtures under normal conditions, 850 K, is 50 - 200° higher than that for most hydrocarbons. At higher pressures, this temperature is greatly reduced. The delay time, i.e. the time between the introduction of heat and self-maintained combustion, is of the order of 0.5 s.

However, it is not only the ignition temperature that is of interest but also the energy necessary to ignite a mixture. The minimum energy for H_2, 20 μJ, is substantially lower than that for competing hydrocarbons, as is shown in Table 14-1. Corona discharges from thunderstorms at considerable distances can cause ignition. Even synthetic fibres in clothes can cause electrostatic sparks, imperceptible to the wearer but energetic enough to ignite the gas. Leaks in high pressure containers or pipelines very often lead to ignition as a result of electrostatic charges developed by the escape of hydrogen.

The low ignition energy introduces a special problem regarding the development of explosion-proof equipment. As is evident from the table, the quenching distance, defined as the gap dimension required to prevent the propagation of an open flame, is very short (0.06 cm) compared to that for the common hydrocarbons. This property makes it difficult to construct flame arrestors capable of successfully disrupting any deflagration which may originate within the equipment.

There is one aspect where a low ignition energy can be regarded as beneficial. If a mixed gas-air cloud gradually accumulates from a spill, an early ignition can prevent the more serious consequences from a larger accumulation of the potentially explosive gas mixture.

After a leak, ignition is most likely to occur when the concentration first reaches the lower flammability limit. If the concentration passes this level without igniting, then it is probable that there are no ignition sources present and ignition will not occur directly. Consequently, the lower flammability must be regarded as a very important safety parameter, irrespective of the total range. In this respect hydrogen is somewhat more advantageous than alternative energy carriers which are usually regarded as being acceptably safe.

When pure hydrogen burns, the flame is nearly invisible in daylight because of the low energy emission. However, the visibility is improved by the presence of moisture and impurities in the air, and it is better in the dark or in a subdued light. By contrast with hydrocarbon flames, which have a strong emission because of the soot formed, with emissivities around 1, the emission coefficient for hydrogen ranges from 0.01 to 0.1 depending primarily on the size and temperature of the flame. Heat radiation during the combustion of LH_2 can be as great as with hydrocarbons, since the low heat of vapourization causes the fire to burn more rapidly and with higher flames. The total heat emission, however, is only a fraction of that for hydrocarbons.

The transparency of the hydrogen flame and the small heat emission can easily result in fires remaining undiscovered for critical periods, and therefore spreading. It is also easy for a person to move right into the flame and be burned. Looking at the beneficial aspects, surrounding objects do not heat up and ignite unless they are touched directly by the flame, and fire fighters can get very close to the flame without injury.

Hydrogen's wide range of flammability and low ignition energy are partly offset by the great tendency of the gas to disperse from the scene of a leak or a spill because of its buoyance and high rate of diffusion, so that compositions lower than the flammability limit are very rapidly reached. In contrast, hydrocarbon leaks and spills lead to the spread of vapours heavier than air in a wide layer near the ground, which greatly increases the hazardous area. Thus we can expect that a fire hazard will develop most rapidly in the order: hydrogen > NG > petrol, and that it will persist in the reverse order. For a specified spillage volume, hydrocarbon fires will persist 5 - 10 times longer than hydrogen fires. All three fuels burn at nearly the same flame temperature, but the scene of a hydrogen fire may be 1.3 - 1.8 times hotter. Water may be used to fight all three types of fire.

The density of GH_2 increases with decreasing temperature and almost corresponds to that of air at the boiling point of LH_2, 20 K. Simultaneously the diffusion coefficient is appreciably lowered. Clouds of hydrogen vapour from a liquid spill may therefore remain near the ground for a long period of time and only disperse slowly. The flame frontier and the visible cloud do not coincide.

As is shown in Table 14-1, the flame velocity for hydrogen lies almost one order of magnitude above that for a hydrocarbonaceous flame. This speed influences the quenching distance, as has already been mentioned. The small value for hydrogen leads to practically total combustion, so that no large quantities of unburnt gas can be found after ignition.

14.2.2 Controlled combustion

The combustion of hydrogen occurs at a temperature of about 2400 K, i.e. at about the same temperature as with hydrocarbon fuels. In a pure oxygen atmosphere, the temperature is appreciably higher, c 3000 K. The addition of water or water vapour lowers the combustion temperature to values that are more compatible with the materials in an internal combustion engine. An added advantage gained by keeping the temperature below 1500 K is that the formation of nitrogen oxides is drastically reduced and kept at environmentally acceptable levels.

With the addition of certain catalysts, the oxidation can occur at even lower temperatures, thereby completely eliminating the formation of NO_x. At low temperatures in the range up to 670 K, precious metal catalysts such as platinum or palladium are required. In temperature ranges above 770 K, non-precious metal catalysts, e.g. thorium-based, can be used.

During combustion, hydrogen is oxidized to environmentally harmless water. The use of hydrogen in internal combustion engines results in practically zero emission of hydrocarbons, SO_2, CO and CO_2; by contrast, there are very large emissions of these environmentally undesirable products when hydrocarbons are used as fuel. Besides NO_x, some formation of H_2O_2 has been reported, but this is not normally the case under optimal operating conditions. Environmental effects are treated in more detail in Chapter 15.

14.2.3 Explosion and detonation hazards

Hydrogen has one of the widest inflammability and detonability limits of any known gases, appreciably wider than for NG and petrol (see Table 14-1). Under normal conditions, a continued combustion (explosion) can be achieved if the hydrogen-air mixture contains in average 4 - 75 % GH_2 by volume. In pipes, the explosion limits are somewhat narrower but they expand with increasing diameter. The limits change with pressure and temperature. At a higher temperature, the upper ignition limit is raised whereas the lower limit remains almost constant. Increasing temperature widens the explosion range.

The pressure peak during explosion is about 7 times greater than the initial pressure, compared to a factor of 20 during detonation. In the presence of obstacles, the latter may rise by a factor of 2 - 3.

Depending on the ignition and confinement conditions, an explosion can turn into a detonation if the composition permits. The limits are closer than those of explosion, but much wider than those for methane (see Table 14-1). There is little evidence that hydrogen explosions in free space can develop into detonations. It is reported that strong shock waves or detonators with a minimum mass of several grams can initiate such a propagation. A confinement of the gas cloud within three walls is, however, sufficient to trigger a detonation, which for large volumes of gas within a completely confined space can attain devastating levels.

With LH_2 spills, the situation is somewhat more favourable as far as detonation safety is concerned. Experiments have shown that in a wide range of LH_2/solid air mixtures an explosion is not possible, let alone a detonation. Only a high concentration of oxygen and strong reflections of pressure waves within a confined space can lead to a detonation.

The wider explosion and detonation limits of hydrogen coupled with its rapid burning velocity tend to make hydrogen a greater explosive threat than NG or petrol, particularly for incidents within a confined space. For equivalent energy or volume storage, hydrogen has the lowest explosive potential of the three fuels considered, even though it has the highest potential on a mass basis. The explosion threat can be completely eliminated by purging with an inert gas like nitrogen or by using a cover of such a gas.

14.2.4 Physiological effects

Hydrogen is physiologically completely inert. Large quantities can be tolerated in breathing air, up to the point where the normal oxygen percentage of 21 is displaced below 13. Concentrations just above 13 % can support life for a number of minutes but below this figure asphyxiation rapidly occurs. Experience suggests that because hydrogen applications require plentiful ventilation to lessen explosion risks, the anoxia problem is of minor importance.

Human tissue exposed without protection to temperatures below 273 K can suffer considerable damage. The extremely low temperature of LH_2 as well as of gas evolving from a liquor spill necessitates preventive measures and careful handling to avoid severe frostbite. Surfaces cooled by or in contact with low-temperature H_2 must also be avoided. However, the likelihood of LH_2 spilling and splashing so as to cause burns is relatively small because of hydrogen's rapid rate of evaporation. Only a massive spill where the environment is so depleted of heat that evaporation will be impeded is likely to involve a serious threat.

Hydrides of alkali and alkaline earth metals are suggested as suitable storage media for hydrogen during transport. In the presence of moisture, these compounds are readily converted into hydroxides which are highly irritating to the skin by caustic and thermal action. Similar effects can occur on contact with eyes and respiratory organs. Powderized hydrides are also known to form easily ignited explosive mixtures with air.

14.2.5 Material compatibility

Hydrogen production processes and handling conditions require elevated temperatures and high pressures as well as cryogenic temperatures. Such conditions may severely degrade the mechanical properties of materials and influence system reliability.

Although hydrogen is known as a non-corrosive medium, experience has shown that material compatibility is a particular safety problem. Potential problems include low temperature effects, hydrogen embrittlement and erosion. Interactions with metals necessitate a careful and restrictive choice of materials in practically all phases of hydrogen application.

At temperatures around the boiling point of hydrogen, only materials which can show a certain amount of elasticity can be used, such as stainless steels, nickel and aluminium alloys. Normal construction steels have too unfavourable mechanical properties. Pure gaseous hydrogen, particularly under pressure, embrittles many materials due to its high diffusivity in metals, which can lead to the deterioration of affected parts in a short time. Small quantities of impurities in the gas, such as e.g. oxygen in a concentration of less than 0.1 %, essentially prevent the embrittlement. Humidification or the addition of small amounts of compounds to make the gas visible or odorous will also significantly increase its material compatibility.

Embrittlement can cause hydrogen storage, distribution and utilization devices to fail, thereby releasing hydrogen which might ignite and burn. The failure of a mechanical part could cause an accident that might be even more serious than a hydrogen fire or explosion. It is generally recognized that occupational and public safety in any future extensive use of hydrogen can only be properly taken care of if all the materials used are carefully evaluated in terms of the relevant conditions.

The phenomena behind embrittlement, the choice of materials and safety precautions against material failure are discussed more fully in Chapter 13.

14.2.6 Safety aspects of the use of LH_2

Liquid hydrogen presents all the hazards normally attendant on the handling of hydrogen plus those of a cryogenic fluid - namely, high volatility and an extremely low temperature. Several of the special handling problems and safety precautions have already been discussed, but some additional aspects are of importance from a safety point of view.

The high volatility along with the unavoidable heat leak into storage containers provides a mechanism for unwanted pressure build-up in containers that are not properly vented. Provisions must be taken, either to safely vent the evaporated H_2 to the environment or to condense the vapours in special equipment and recirculate the liquor to the container. In large cryogenic vessels, evaporation losses can be expected to be less than 0.1 % per day. If there is a loss of insulation, the pressure can rise very rapidly. Release valves or rupture disks must function properly in order to prevent the destruction of the vessel.

The temperature of LH_2 at normal pressures is sufficiently low to solidify all gases and liquids except helium, which has a lower boiling point. Air in contact with LH_2 or with the surface of an uninsulated LH_2 vessel solidifies rapidly. The condensate is enriched in oxygen to approximately 50 % and can give rise to explosive mixtures in contact with combustible materials. Damage or hazard can also be caused by cold embrittlement or dimension changes in materials not intended to withstand a temperature approaching 90 K. A mixture of LH_2 plus solid air presents a highly dangerous explosion hazard. Solidified air can also plug vent paths and connection lines of LH_2 containers and jeopardize their integrity because of pressure build-up. All filling procedures for an LH_2 container system must therefore be coupled with helium purging before and after the operation, in order to avoid any contact with air.

During the liquefaction of hydrogen, extreme precautions must be taken in order to reduce below the 1 ppm level any impurities which would otherwise freeze-out. Such condensed solids exhibit virtually no vapour pressure at 20 K and can thus accumulate indefinitely.

In spite of the hazards discussed, the use of LH_2 has an excellent safety record which reflects the research done concurrently with the expansion of LH_2 technology. At the present level of use and with well-trained personnel handling all operations, the existing controls and equipment appear to be adequate. A widespread use of LH_2 in distribution networks, service depots and vehicles may later cause real concern.

14.3 Earlier experience, accident analysis

Hydrogen is an important feedstock for industry, and thus many miles of hydrogen pipelines exist for chemical applications. All of the systems are short (< 220 km), operate at relatively low pressures (< 5 MPa) and have rather small diameters (< 30 cm), but they have been used for a long time (in Germany for more than 40 years). Thus they have demonstrated that it is possible to transmit hydrogen safely and that material problems can be overcome (3, 8). Many incidents have occurred involving large volumes of GH_2, but the consequences have always been limited both from a material and an economic point of view. A recent analysis (9) indicates that the explosive damage resulting from hydrogen accidents is no larger than that from NG accidents, though the frequency is higher. Capital equipment losses are also higher; this reflects the more expensive equipment associated with H_2 systems.

NASA and the aerospace industry probably have most experience with high-pressure GH_2, which is used for tests of rocket engines. Hydrogen is safely handled in these facilities at pressures up to 100 MPa (10). No major failures have been reported for the transmission systems which are constructed from austenitic stainless steel. However, several failures have occurred in high-pressure storage tanks operating in the range of 35 MPa.

Where pipelines do not already exist, hydrogen is primarily transported to all but the smallest users as a liquid, regardless of the final use. In spite of the difficulties of handling cryogenics, long experience has shown that this can be done both safely and economically. By comparison with the largest GH_2 tube trailer, which can transport 3 800 m^3 of (NPT) gas, a highway trailer can carry up to 50 m^3 of LH_2 (equivalent to ~ 42 000 m^3 GH_2) and rail tank cars c. 100 m^3. Such transports are in routine use today in the USA. The largest transport capacity is 950 m^3, for tanks mounted on seagoing barges. The safety record is excellent with no fatalities or serious injuries. Many incidents have occurred, including traffic accidents, pipe ruptures and leaks, with spills or leakage of tons of hydrogen followed by explosion and fire. In a few cases property damage has been extensive though locally concentrated, but no serious injuries to individuals have been reported (1).

In Europe much experience has been gained in hydrogen handling in a German rocket-engine development program (11). More than 100 m^3 of LH_2 has been used for the experiments, and c. 100 000 m^3 of GH_2. The accumulated transport distance for 700 LH_2-transports is about 270 000 km. No critical situation has occurred in any of the phases of filling and emptying the LH_2 tank lorries. All systems and procedures have proved to be satisfactory without requiring major changes. No critical traffic situation has occurred, although difficulties resulting from winter conditions and from high traffic density had to be overcome, and technical defects appeared in the tank systems during transport.

The excellent safety record maintained by the US space program and NASA in their use of vast quantities of hydrogen and particularly LH_2 offers encouragement about the safe use of gaseous or liquid hydrogen. Liquefiers with capacities in the range of 6 to 60 tons/day were operated. A total liquefaction capacity of about 200 tons/day was eventually reached. Cryogenic storage vessels, with the inner shell made of stainless steel and the outer of carbon steel, were constructed in sizes up to 3200 m^3 and with working pressures of 0.62 MPa. The measured boil-off rate of the largest sizes which are still in use today is 0.03 %. Means of pressure-building by an external heat exchanger is provided along with remote and manual valves and controls. Nevertheless, the excellent NASA experience is inadequate to serve as a basis for decision making concerning a future hydrogen economy, where the substance would be more generally handled by the public.

Several systematic analyses of accidents involving hydrogen in industrial processes as well as in research and development studies have been presented (1, 9, 12, 13). Mishaps occurred primarily when procedures had not been prescribed or appropriately followed. Lack of inadequate purging was a frequent cause of hydrogen fires and explosions. Inadvertent cryopumping, condensation and freezing of the air component is unique to cryogens like LH_2, and several instances of such problems have occurred. Other common causes were undetected leaks, improper venting and off-gas explosions, safety disk failures and piping and pressure vessel ruptures. According to NASA experience (12), electrical short circuits and sparks appear to be responsible for 25 % of the release ignitions and static charges for about 18 %. Releases were normally to the atmosphere with little or no damage to the surroundings, but for about 20 % of the incidents the release was into an enclosure with much more severe consequences. Traffic incidents have largely been operational and minor in nature, with no unusual risk to the public.

A large percentage of the accidents have been traced to failure of or leakage from gasketed joints, flanges and valve packings. Leakage losses in NG systems have been estimated to amount to as much as 10 % of the total use. There is frequently a concern that hydrogen will leak faster. It is true that the leakage can be expected to increase by a factor of about three, but due to its lower energy density the total energy release will approximately equal that of NG and will have about the same safety consequences in non-confined areas.

Off-gas systems and furnaces have been involved in hydrogen accidents more often than any other equipment. Compressors and heat exchangers have also frequently been involved. The relatively high incident rates are understandable since these systems usually contain the gas at temperatures near or above the autoignition point. In view of one of the intended future production methods of hydrogen, viz. water electrolysis, it is important to realize that electrolysis malfunctions have a high incident rate. Therefore careful consideration must be given to the safe and complete separation of hydrogen and oxygen product lines.

Industrial practice hitherto does not suggest that any new technology is needed for the safe handling of hydrogen or hydrogen mixtures. Incidents rather show the need for more attention to established procedures, equipment maintenance, procedural planning and operator training.

14.4 Preventive measures

In a future hydrogen economy, hydrogen cannot be used without new and additional safety measures, otherwise there would be an intolerable risk for the population. This means that such low-cost conditions which are normal for conventional hydrocarbons today will most certainly not be attainable. Rising costs, many times higher than those required at present for safety devices, are to be expected.

The first step towards a widespread use of hydrogen must include an appropriate training of the population. These measures and regulations more or less correspond to those at present imposed on trained personnel. The training must begin at an early stage, before the first household burners are being converted to hydrogen and the first hydrogen-motor cars appear on the market. The direct handling of LH_2 and LH_2 equipment will probably always be a restricted area for the general public.

The most prominent aspects of the training should include:

The dangerous properties of the highly flammable gas, which requires the greatest care.

The avoidance of every possible source of ignition in the vicinity of hydrogen apparatus.

The permanent control of ventilation devices in rooms where hydrogen is used.

The continuous check of catalyst burners.

Only adequately trained personnel being allowed to install, repair and service hydrogen apparatus.

No entrance to areas where hydrogen is used, stored or transported without a check of the ventilation.

Immediate evacuation of endangered areas.

14.4.1 General safety appliances

The general safety measures comprise especially ventilation, hydrogen leak and fire detection devices, and prevention of ignition sources.

In case of a leak, sufficient ventilation or diffusion with an inert gas, such as nitrogen or carbon dioxide, must be provided so that the mixture quickly falls below the lower ignition limit. As little as 4 % of oxygen under otherwise optimal conditions can result in an explosion. Entirely enclosed rooms, such as kitchens or garages, require circulating devices like fans or air-vents. Excessive hydrogen from leakage or depletion of tanks should either be catalytically burned or directly vented to the atmosphere.

The detection of leaking hydrogen is essential for the initiation of safety measures, such as closing of lines and starting ventilation. Detectors should be installed in all areas where hydrogen is used. These are at present based upon catalytic combustion, mass spectrography or electrochemical processes. Cheaper devices must be developed for widespread use, for example ultrasonic sound apparatus. Hydrogen flame detectors are also desirable for a complete safety system. Up to now ultraviolet devices have been preferred, but more economical and reliable detectors are desirable in the future. The use of an odourizing agent and a flame colorant would greatly reduce the requirements of detectors for domestic application.

The elimination of ignition sources is an important preventive protection measure, but this is generally not adequate for the complete prevention of hydrogen explosions because of hydrogen's very low minimum ignition energy. Inside a system, the prevention of oxidant ingress is therefore an absolute prerequisite. This may be achieved either by ensuring overpressure against the oxidant atmosphere or by using inert gases. One way of suppressing the progress of an explosion is to use flame arrestors. Because of the short quenching distance of hydrogen, it is difficult to design reliable arrestors. Other protective measures to prevent dangerous damage from explosions inside systems containing hydrogen are for example the provision of blow-out panels, burst discs and relief valves, plastic curtains and protective barriers to guard against fire, shrapnel and overpressure.

Preventive measures against hydrogen explosions in outside systems are much more limited in their effect, since an oxidant is always present and the presence of an ignition source of sufficient energy can never be completely excluded. However, all electrical equipment in the vicinity should be grounded and prevented from short-circuiting to minimize electrostatic spark hazards. Further measures to prevent ignition sources include the use of explosion-proof equipment and spark-proof tools, flame arrestors and the elimination of hot surfaces. The rapid dispersion of hydrogen provides the best protection against a dangerous explosion. Appropriate ventilation or better open-air installations are therefore the best preventive measures. Measures which only protect against further effects from fire and explosions are for example automatic process shut-down systems, sprinklers, deluge systems and various fire-fighting equipment.

Special precautions must be taken when liquid hydrogen is stored or handled. All contact with air or any other contaminants must be completely excluded. An inert purging gas, either helium or hydrogen, must therefore be properly applied in all filling and other transport operations. The entrapment and freezing of moisture in cryogenic vent pipes, relief valves and burst disc exhausts must be avoided. If possible, storage tanks should be diked and spills should be protected from any contact with combustible material. In all systems, overpressure should be applied in order to prevent the entrance of air.

All construction materials in contact with gaseous or liquid hydrogen should be compatible with the substance at the appropriate temperature and pressure, so as to elimininate martensitic transformations, embrittlement and nonductile failures.

14.4.2 Modifications of the safety characteristics of hydrogen

Usually, gaseous hydrogen as an energy carrier is not used in its pure form. An exception is the conversion of GH_2 to electricity in fuel cells when only very minor amounts of contaminants can be tolerated. Otherwise, the addition of smaller or larger amounts of suitable gases and particles can often considerably improve the safety characteristics of the gas. These alterations primarily concern ignition and combustion properties, and material compatibility. The addition of 10 % methane, for example, lowers the upper ignition limit to approximately 2/3 of the pure hydrogen value. A concentration of less than 1 % of almost any gas gives a remarkable improvement of the material compatibility.

Certain substances which are added to GH_2 in particle form, and thus help to create an aerosol, can greatly suppress explosiveness. An example of this is $Fe(OH)_3$.

Hydrogen in its pure form is an odourless gas with a transparent flame, so that neither can be perceived by the human senses. The sulphur compounds now used to odourize NG are compatible with H_2 and therefore appear to be a satisfactory solution. However, the addition of any material, especially sulphur-bearing compounds, to hydrogen used in catalytic processes could cause considerable problems. An alternative is to develop new odourants which do not contain sulphur and which do not interfere with catalysts. Such studies are at present in progress.

The addition of an illuminant, which would make the flame visible, would increase the safety in open-flame appliances and assist in the adjustment of burners. No suitable compound has yet been identified, but two types of material appear to be appropriate. One is a small amount of an aromatic-type organic material that would burn with a yellow flame, and the other is a trace of a volatile organo-metallic sodium compound that would give the flame the characteristic sodium-yellow colour.

14.5 Future research

Before a safe, cost-effective hydrogen economy can be realized, some additional research remains to be carried out. Some of these items are discussed in each chapter of the applied sectors, where those safety matters that are especially valid for the appropriate application are also considered in more detail.

The emphasis of future research activities should be directed towards the following areas:

An evaluation of the consequences of large spills of GH_2 and LH_2. Factors needing better elucidation include the dispersion and distribution of hydrogen after a leak or spill, the effects of size, rate and mode of such spills, and the effect of materials and environment on the vapourization rates.

The combustion process of hydrogen in air and oxygen, particularly the transition to explosion and detonation and its dependence on flame front velocity. The effects of quantity, impurities, confinement and strength of ignition source need to be investigated.

The establishment of appropriate flame-arrestor criteria and the development of reliable devices.

The development of cheap and reliable hydrogen detectors for industrial and household use.

The evaluation of odourants and illuminants for improved leakage and flame detection.

The design and testing of improved gaskets for hydrogen service.

The development of efficient fire controlling and fire fighting techniques including the assessment of thermal radiation effects and the effects of vapour absorption.

The systematic evaluation of hydrogen embrittlement and material compatibility characteristics for practical containment materials. Tests must be run under reproducible conditions of temperature, pressure , hydrogen purity, stress state etc and should include the effectiveness of plastic coatings.

14.6 Conclusions

There is no point in denying the danger implicit in a future widespread use of hydrogen as an energy carrier. Hydrogen has some special properties that require more careful handling procedures than for any fuel in common use today. Compared to natural gas, GH_2 is much more prone to leak, embrittles most ordinary construction materials, can be ignited by extremely low quantities of energy and is flammable and explosive over a wide range of H_2-air mixtures. Furthermore, the gas is colourless and odourless, has a very low heat emissivity and burns with an almost invisible flame. An involuntary move into a hydrogen fire can therefore not be disregarded as an improbable incident. In liquid form, the extremely low temperature of hydrogen can solidify any substance except helium in contact with it. The mixture with air becomes enriched in oxygen and is highly explosive.

The damning list of negative properties is partly counterbalanced by the high buoyancy and diffusivity of the gas. Consequently, a leak seldom leads to a concentration sufficient to sustain ignition and, unlike petrol, methanol and NG, GH_2 rapidly departs from the scene of spills and leaks. If ignited, the very short quenching distance causes immediate and total combustion. Explosions in free space can only rarely develop into detonation. A confinement within three walls may, however, be sufficient to trigger a detonation.

During combustion hydrogen is oxidized to environmentally harmless water. Except for limited amounts of NO_x compounds, no other emissions are obtained. By keeping the temperature below 1500 K or by the use of certain catalysts, the formation of NO_x can be drastically reduced.

Hydrogen is physiologically inert. Large quantities can be tolerated up to the point where asphyxiation occurs. On the other hand, LH_2 must be handled with great care, since human tissue exposed to its low temperature can suffer considerable damage.

Hydrogen has been used as a transmissible fuel in town gas for 100 years and as a portable fuel in cryogenic form within the last 30 years. It is also an important feedstock for chemical industry. The long and comprehensive experience has demonstrated that hydrogen in large amounts can be safely stored, transported and applied and that materials problems can be overcome. A great many incidents and also several more serious accidents have occurred, but the fatalities are low and the damage has seldom been extensive. Considerations of future hydrogen applications reveal no insurmountable problems in the industrial and commercial market, as long as prescribed safety rules are rigorously followed and the equipment is handled by well trained personnel. The excellent safety records must not be interpreted so as to allow a general handling of hydrogen and its equipment by unskilled persons.

In a future hydrogen economy, new and more elaborate safety measures must be developed and executed so as to decrease the risk for the population. The greatest contribution to safety is achieved by thoughtful processes worked out ahead of time by competent authorities. Others include an appropriate training of the public, improved safety characteristics of hydrogen and the development of cheap methods and instruments which can rapidly detect minor leaks or spills, or prevent or limit the consequences of such occurences. One of the major obstacles to a transition to a hydrogen economy might be the present public perception of hydrogen as an exceptionally dangerous substance which can cause major catastrophes, such as the total breakup of the Zeppelin Hindenburg during the thirties.

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15. HEALTH, ENVIRONMENTAL AND SOCIETAL IMPLICATIONS

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15.1 Introduction

All the carriers which are expected to provide Sweden with energy in the future are associated with health and environmental risks, but these are of greatly varying intensities. Much consideration must be given to these risks in the design of the future energy policy.

An attempt can be made to quantify these risks by carrying out a comparative risk analysis of different production methods for the competing energy carriers, according to the three scenarios sketched in Chapter 4. The analysis deals with health, other environmental and societal implications. It is based on deleterious effects on mankind, materials, environment and society due to pure accidents as well as normal and accidental releases of poisonous products during the complete cycle for the production and application of the competing energy carriers. The risk factors obtained are quantified in terms of costs by multiplying them with a specific cost factor, which is directly related to the risk factor unit.

Health risk factors have recently become available in the literature for the principal methods of producing energy and energy carriers. A complete analysis of health implications has therefore been attempted. There are no similar data available for other environmental effects including material costs due to accidents. A deductive method has been implied in order to partly quantify their implications. For the present, no method has been found by which the social implications can be put into cost figures of any reliability.

15.2 Health implications

15.2.1 Description of method

The detailed risk calculations are centered on three aspects of the energy production cycle, Figure 15-1:

- plant construction, fuel production
- transportation
- operation and maintenance.

The unit chosen to express the risks is the PJ of net energy obtained from the energy source. The meaning of this term will be explained later in this chapter.

For each of the above-mentioned aspects, data are required on the frequencies of illness, accidents and deaths. They are all applied for two risk groups: occupational and public. Occupational risk can be defined as that which occurs at the working place. Public risk is mainly incurred by people living close to the site of an energy system. Since we are concerned with the risk per unit of energy over the entire span of production of a given system, its lifetime is of importance. For most of the systems considered, a lifetime of 30 years has been assumed.

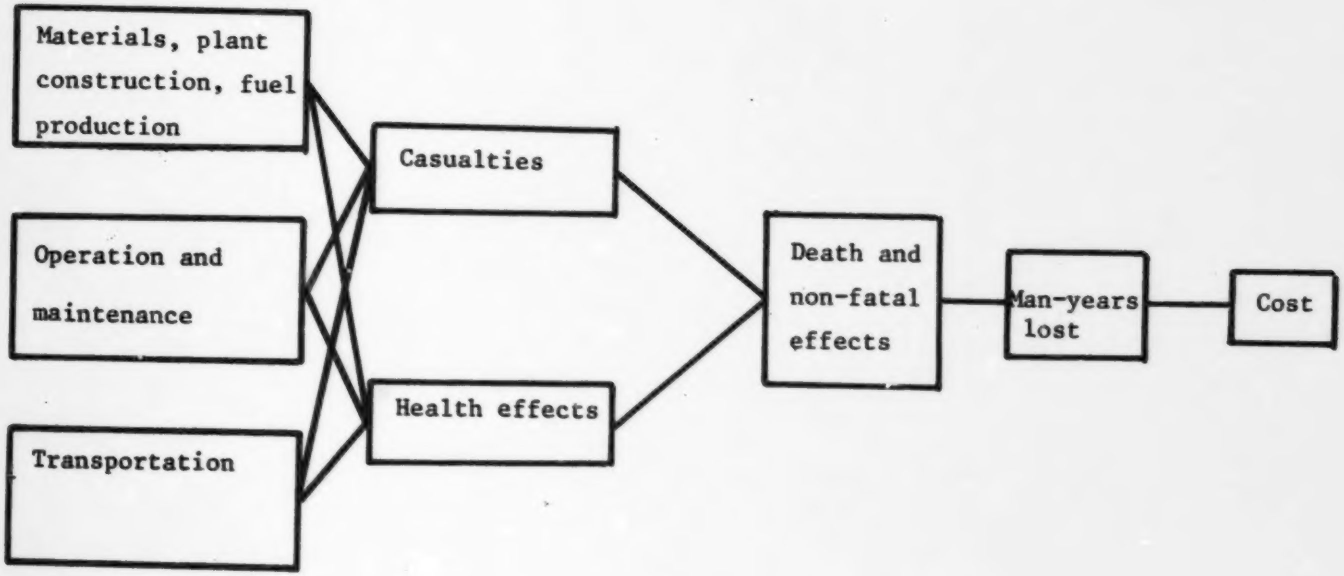
Materials, plant construction, fuel production
Operation and maintenance
Transportation
Casualties
Health effects
Death and non-fatal effects
Man-years lost
Cost

Figure 15-1

Sources of risk in energy production and their impact on man.

Comparisons between deaths and less severe health problems, such as accidents and disease-related disabilities, have been reported in many studies, e.g. (1, 4, 5). In this study it is assumed that each death is equivalent to a loss of 7 500 man-days, and each percentage of disability to a loss of 75 man-days (1). The median accident in 1973 (2) implied a degree of disability of 16 percent and thus accidents were considered to account for a loss of 1 200 man-days. A simplified assumption of the above type is used in this study to compare deaths with accidents and disease. A man-year is taken as being the equivalent of 200 man-days.

The cost of each man-day lost is considered to be 200 cr, i.e. one man-year costs 40 kcr (1).

For the three aspects of the energy production cycle, Figure 15-1, there are many types of risk. For some systems such as coal, much of the occupational risk arises from mining and comparatively little from construction. For systems like solar space heating, most of the risk is linked to the construction side and almost none to the fuel production. In 15.2.2 the major types of risk are quantified for each energy system.

Some energy systems, such as windpower and solar plants, require energy back-up. The type of back-up chosen will influence the risk. Herrera (3) says:

> "It is unlikely that a nuclear plant will be used for a solar plant back-up since a nuclear plant is less suitable for peak-power production. Oil or gas are more likely choices, but these fuels will tend to be unavailable toward the end of the century. Therefore, the future extra back-up margin will more likely be based on coal."

15.2.2 Applied risk figures

In order to simplify matters for the reader, the results for each primary energy source are presented in the form of tables etc with brief explanations. The tables include the main components which contribute to the total risk figure. The following comments will help to explain what is involved for each component.

- Fuel mining, raw material production

  To illustrate the reasoning used, consider two technologies: solar space heating and coal-fired electricity plants. In terms of raw material and fuel production, solar space heating requires the mining of metal for tubing, while the coal-fired plant requires the mining of coal as fuel, iron for building turbines etc.

- Fuel handling, refining

  Before the fuel and raw materials can be used for the production of energy, they have to be processed and adapted to the production.

- Material acquisition and construction

  The raw material must be moved to an appropriate destination for fabrication into components. The components are then moved to the building site and assembled into a power plant.

- Emissions

  Only discharges of pollutants caused by material production are included.

- Operation and maintenance

  All work is included which has to be done in order to promote plant operation and the production of energy. Emissions from the energy production process are also included here.

- Transportation

  plays a significant part in the energy cycle. It is shown as an interaction with the other components in the figures.

- Energy back-up and storage

  All energy production systems have storage systems. Some are less obvious than others. Some non-conventional energy sources, such as solar and wind, require comparatively large storage systems for the time when their energy source is unavailable. Other non-coventional sources require additional "back-up" energy in the form of conventional energy.

- Waste management

  refers to the treatment of nuclear wastes.

The basic data are taken principally from three references (1, 4, 5). Risk figures are given as lost man-years per PJ energy content of the primary and secondary energy sources discussed.

15.2.2.1 Coal

There are many possibilities for generating energy using coal. In the literature, over 21 possibilities are mentioned, both present and potential. To keep the calculations within bounds, only three of those using present-day technology will be considered in this study:

- electricity generation
- hot water production
- methanol production

Table 15-1

Electricity production (1), loss of man-years/PJ

Fuel mining	2.7 - 27
Fuel handling*	0.2 - 0.6
Transportation	4.4 - 12
Operation and maintenance*	1.4 - 120
Total	9 - 159

---

* Including material acquisition and construction.

Table 15-2

Hot water production, loss of man-years/PJ

Fuel mining	1.3 - 12
Fuel handling*	0.1 - 0.3
Transportation	2.0 - 5.5
Operation and maintenance*	0.6 - 55
Total	4 - 73

Table 15-3

Methanol production (1, 4, 6), loss of man-years/PJ

Fuel mining	21 - 207
Fuel handling*	8 - 15
Operation and maintenance	16 - 553
Transportation	2.6 - 32
Total	48 - 807

15.2.2.2 Oil

Like coal, oil has a wide field of application. Oil may be transported to a refinery by either pipeline or tanker. At the refinery, crude oil is transformed into a number of petroleum products. Here the risks associated with the following four methods are considered:

- electricity generation
- hot water production
- petrol production
- Diesel-oil production

Table 15-4

Electricity production (1), loss of man-years/PJ

Raw material production	0.7 - 2.7
Refining*	0.6 - 2.6
Transportation	0.7 - 3.7
Operation and maintenance*	1.5 - 119
Total	4 - 128

---

* Including material acquisition and construction.

Table 15-5

Hot water production, loss of man-years/PJ

Raw material production	0.3 - 1.2
Refining*	0.1 - 0.3
Transportation	0.4 - 1.6
Operation and maintenance*	0.7 - 59
Total	2 - 62

Table 15-6

Petrol production (1, 7), loss of man-years/PJ

Raw material production	0.3 - 1.3
Refining*	0.1 - 0.3
Transportation	0.6 - 2.5
Energy production	2.2 - 188
Total	3 - 192

Table 15-7

Diesel-oil production (1, 7), loss of man-years/PJ

Raw material production	0.6 - 3.0
Refining*	0.3 - 0.5
Transportation	0.8 - 4.6
Energy production	1.7 - 143
Total	3.4 - 151

15.2.2.3 Natural gas (NG)

Since no data are available for natural gas, an indirect method was used for calculating the risk (15). The results are not expected to differ greatly from those of a more direct method.

Three ways of producing energy are analysed

- direct use as an energy carrier
- electricity generation
- hot water production.

Table 15-8

Energy carrier (4), loss of man-years/PJ

Raw material production and fuel handling*	0.3 - 2.5
Transportation	0.2
Operation	0
Total	0.5 - 217

---

* Including material acquisition and construction.

Table 15-9

Electricity production (4), loss of man-years/PJ

Raw material production and fuel handling*	0.8 - 6.3
Transportation	0.4
Operation and maintenance	0.2 - 0.5
Total	1.4 - 7.2

Table 15-10

Hot water production, loss of man-years/PJ

Raw material production and fuel handling*	0.4 - 2.8
Transportation	0.2
Operation and maintenance	0.1 - 0.2
Total	0.7 - 3.2

15.2.2.4 Nuclear power

There are several ways of generating nuclear power. The system generally applied in Sweden, the light water reactor, will be considered here.

The number of man-hours required during the construction period is comparable to those for coal and oil. The operation and maintenance values are considerably lower than for coal, since a uranium miner mines about ten times more energy per hour than a coal miner. Another difference is that fewer metals are needed for a nuclear plant construction than for coal or oil. However, this is counteracted by the large amount of concrete used. This material forms a large part of the main reactor building.

Two methods and their risks have been analysed:

- electricity generation
- hot water production.

Table 15-11

Electricity production (1, 20), loss of man-years/PJ

Fuel mining*	0.5 - 9.3
Fuel handling*	0.1 - 0.9
Transportation	0.03 - 0.05
Operation and maintenance	0.3
Waste management	0.05
Total	1.0 - 11

---

* Including material acquisition and construction.

Table 15-12

Hot water production, loss of man-years/PJ

Fuel mining*	0.2 - 3.9
Fuel handling*	0.05 - 0.4
Transportation	0.02
Operation and maintenance	0.12
Waste management	0.01
Total	0.4 - 4.4

15.2.2.5 Biomass

The raw material for energy production is wood. The plant for energy production - by combustion that converts biomass directly into usable heat - is assumed to be similar to the coal-fired one. Transportation risks are higher than those for oil or coal because of a more bulky and difficult mode of conveyance.

Wood can also be used as a raw material to produce methanol. Methanol is expected to be used as a substitute for petroleum products in road and sea transportation.

Table 15-13

Electricity production (1, 8), loss of man-years/PJ

Raw material production and fuel handling*	3.7
Transportation	12 - 45
Operation and maintenance	1.4 - 120
Total	17 - 169

Table 15-14

Hot water production, loss of man-years/PJ

Raw material production and fuel handling*	1.8
Transportation	5.7 - 21
Operation and maintenance*	0.7 - 56
Total	8 - 80

Table 15-15

Methanol production (4, 8, 9), loss of man-years/PJ

Raw material production	12
Material, acquisition and construction	69 - 581
Transportation	43 - 182
Operation and maintenance	16 - 553
Total	140 - 1328

---

* Including material acquisition and construction.

15.2.2.6 Peat

The peat cycle includes raw material acquisition, transportation and energy production. Combustion is the main conversion process for obtaining usable heat from peat. However, peat, like biomass, can be converted into a secondary fuel, e.g. methanol.

As in the case of biomass, three possible methods of producing energy have been studied

- electricity generation
- hot water production
- methanol production

Table 15-16

Electricity production (1, 8, 19), loss of man-years/PJ

Raw material production and fuel handling*	3.8
Transportation	12 - 45
Operation and maintenance	1.4 - 120
Total	17 - 169

Table 15-17

Hot water production, loss of man-years/PJ

Raw material production and fuel handling*	1.8
Transportation	5.7 - 21
Operation and maintenance	0.7 - 56
Total	8 - 80

Table 15-18

Methanol production (1, 4, 8), loss of man-years/PJ

Raw material production and fuel handling	12
Material, acquisition and construction	70 - 582
Transportation	3 - 32
Operation and maintenance	16 - 553
Total	101 - 1179

---

* Including material acquisition and construction.

15.2.2.7 Hydrogen

The dominant risk and the major source of pollution when using hydrogen as a fuel is to be found in the energy sources necessary for hydrogen production. Two ways of producing hydrogen are analysed, coal gasification and electrolysis by nuclear produced electricity. The energy efficiencies are assumed to be 50 and 80 %, respectively.

Table 15-19

Coal gasification, loss of man-years/PJ

Material acquisition and construction, fuel handling	0.2 - 0.8
Primary energy source	7.2 - 127
Transportation	0.2 - 1.2
Operation and maintenance	0 - 0.2
Total	7.6 - 129

Table 15-20

Electrolysis (nuclear el.), loss of man-years/PJ

Material acquisition and construction, fuel handling	0.2 - 0.8
Primary energy source	1.3 - 13.8
Transportation	0.2 - 1.2
Operation and maintenance	0 - 0.2
Total	2 - 16

Transmission

The technique to be used for transmission is in pipelines for gaseous hydrogen and in bulk for the liquid form. Hydrogen can be transported through similar transmission networks which already exist for natural gas (see Chapter 7).

Accidents during the use of trailers, tankers and lorries resulting in property damage or loss of life have occurred at a rate of 1 in 0.03-0.05x10^9 m^3, which corresponds to 1 in 20 -30x10^9 km of road transport (11).

Storage

Hydrogen can be stored as a compressed gas, as a liquid or in solid hydride forms. Storage techniques and storage problems are similar to those for petrol and natural gas. By experience and analogy it appears to be correct to imply that all three fuels can be safely contained both as gases and in the liquid form. The degree of risk associated with the storage of each fuel is not known exactly but it can be assumed to be small (12).

NASA has summarized the causes of hydrogen accidents connected with the transportation and storage of hydrogen (13):

Procedural deficiencies	25 %
Planning deficiencies	14 %
Material failures	< 3 %
Design failures	22 %
Operation and work area deficiencies	26 %
Malfunction	8 %
Material incompatibilities	< 3 %
Contamination	< 1 %

It can be noted that 71 percent of the hydrogen releases did not lead to an ignition.

15.2.2.8 Solar power

Solar energy belongs to the "non-conventional" energy sources. Less is known about them, in terms of risk, than about more conventional sources. There are several ways of using solar power for energy production. The following are analysed here:

- generating thermal electricity
- generating photovoltaic electricity
- producing hot water.

The first method converts solar to thermal energy using solar concentrators. Briefly, a tall tower stands in the centre of a large field of mirrors. The mirrors reflect sunlight to the top of the tower where a fluid is heated to steam. The steam runs conventional electricity generating turbines.

Because of the large amount of materials used in the construction of solar thermal electric plants, the emissions produced during their acquisition can have a significant effect on public health. These impacts are negligible for conventional plants because so much less material is involved.

As mentioned in the description of methods, coal is used as a back-up. The back-up energy will depend on how often back-up is used. The back-up energy is estimated to be about 19 % of the rated solar plant energy (16). In order to calculate the extra risk due to back-up energy, this factor is applied to the total risk incurred by coal, as noted in Table 15-1. The risk is from construction and operation.

Table 15-21

Thermal electricity (4), loss of man-years/PJ

Material acquisition and construction	23
Emission	19 - 29
Operation and maintenance	9.4
Energy back-up and storage	9 - 55
Transportation	3.8 - 12
Total	64 - 128

A photovoltaic plant generates power by converting solar energy directly to electricity by means of photocells. Individual photocells are arranged in modules, which are used in a switchable network to maintain a constant voltage output level. From each array in the collector field, there are transmission lines to the central power station.

Emissions will be proportional to the weight of coal used for the construction. Studies show that for a photovoltaic plant this weight is about 1.1 times more than that for a solar thermal plant. The emission risk for the latter is therefore multiplied by this factor.

A photovoltaic system needs approximately the same amount of energy back-up as a solar thermal system.

Table 15-22

Photovoltaic electricity (4), loss of man-years/PJ

Material acquisition and construction	72
Emissions	21 - 32
Operation and maintenance	9.4
Energy back-up and storage	9 - 55
Transportation	5.2 - 16
Total	117 - 175

The last method which has been analysed is solar space heating. Solar energy is used directly to heat water or other fluids, which in turn are used for industrial or domestic space heating or hot-water applications. No energy back-up is required, since the storage system is assumed to supply enough energy for sunless days.

As in the two previous applications of solar energy, it is assumed that emissions incurred in material production are proportional to the weight of coal used to fabricate the material. About 4 times more coal is required compared to that for a solar thermal plant.

Table 15-23

Space heating (4), loss of man-years/PJ

Material acquisition and construction	55
Emissions	71 - 111
Operation and maintenance	28
Transportation	2.5 - 7.5
Total	156 - 202

15.2.2.9 Wind

One of the problems when calculating wind-power risks is to determine the relationship between maximum power and average power. Another problem is to calculate the amount of material required for wind power plants. One estimate is given in Table 15-24. Compared to solar systems, requirements are lower by a factor of four.

Table 15-24

Materials required for windmills with an average output of 1 PJ per year, in Mtons.

	Steel	Copper	Plastics	Concrete
Windmills	0.4	0.01	0.06	
Foundations				0.01
Total	0.4	0.01	0.06	0.01

The emissions due to wind power will be considerably more than those arising from solar space heating, primarily because of the relatively large amount of coal required to build a windmill.

Wind power is weather-dependent like sun power. It is therefore assumed that the energy back-up is about the same as for solar thermal or solar photovoltaic energy.

Table 15-25

Electricity generation (4), loss of man-years/PJ

Material acquisition and construction	140
Emissions	248 - 362
Operation and maintenance	50
Energy back-up and storage	9 - 55
Transportation	2.1 - 31
Total	449 - 638

15.2.2.10 Hydroelectricity

At present hydroelectric stations generate the largest proportion of electricity in Sweden.

The risk due to hydroelectricity can be divided into two parts: that incurred in material acquisition, construction and other forms of normal operation, and that due to catastrophic dam failures.

Only routine risks are considered here, to make the figures comparable with the risks due to the other types of power production.

Table 15-26

Electricity generation (4), loss of man-years/PJ

Material acquisition and construction	66 - 67
Operation and maintenance	3.2
Transportation	1.2 - 3.6
Total	72 - 78

15.2.3 Summary of risk and cost factors

The results obtained are summarized in Table 15-28 and Figure 15-2. The risks have been converted into costs by multiplying the geometrical mean risk by the cost of one man-year given earlier, 40 kcr. This cost is expressed in cr per GJ to make it directly comparable with other cost values obtained for the energy carriers in this project study.

The results show that some of the non-conventional energy sources tend to have considerably higher risks than nuclear power, the newest of the conventional sources. The ratio is in some cases as high as 10 - 100.

15.3 Environmental implications including material costs due to accidents

Energy will be required for many different activities in the future, in the form of either electricity, heat or fuel for engines. The decision about what constitutes a suitable combination of the various methods, in order to meet a given demand for energy, will depend on for example technical, economic and environmental factors. Thus we are not justified in considering only the production of electricity when discussing future sources of energy. Instead it is necessary to consider the whole picture.

All conversion of energy has an effect on the environment. In 15.2 we discussed the health risks to mankind resulting from the different methods of producing energy. An attempt is made is made here to evaluate the environmental risks from different kinds of energy carriers. The results of the evaluation are summarized in Table 15-28.

15.3.1 Organic and fossil fuels

These include materials such as coal, oil, natural gas, biomass and peat. Environmental effects are here defined as changes in an ecosystem resulting from the impact of the whole energy cycle, from raw material production to waste management.

15.3.1.1 Global atmospheric

There is much concern about the impact of the use of organic fuel as an energy resource because of its potential for altering the world's climate. A difference in surface temperature of only a few degrees sustained over several years may be sufficient to trigger major climatic changes. Even minor climatic alterations may have a significant effect on world agricultural production. This effect stems from the release of carbon dioxide, which tends to warm the earth through the well known "greenhouse effect".

15.3.1.2 Localized effects on water

The major vectors affecting water originate from coal mine drainage, oil spills and power plant cooling. Coal mine drainage has literally destroyed thousands of kilometers of waterways in Appalachia. Extensive research efforts have been made to find ways to understand, prevent and remedy this problem ([illegible]7), but it is complex and remains largely unsolved. The cost of controlling damage from coal mines can be great, but for the US as a whole, coal mine drainage contributes only a few percent to the total water pollution problem.

Oil spills result from accidents with tankers, at offshore drilling rigs or at port storage facilities. Major oil spills can have devastating short-term local effects on beaches and ocean life. Hydrocarbons are rapidly taken up by fish and shellfish. Accidental spills form only a part of the total release of oil into the oceans by man. Other major sources include the discharge of oil-contaminated ballast, direct leakage of fuel and lube oil and fallout of unburned oil which is released to the air from oil-burning ships. One third to one tenth of the oil released to the oceans comes from natural seeps.

The cooling water required for electric power plants can also have an influence on the aquatic habitat in rivers, lakes or estuaries.

15.3.1.3 Localized effects on air

Emissions of various compounds into the air result from the employment of organic fuels for energy production. This applies in the first place to coal, oil and NG. Biomass, peat and organic wastes are produced over a relatively short period immediately before they are used, unlike the fossil fuels which have been stored for millions of years. The emissions, resulting from their combustion, therefore do not imply any additional contribution of air pollutants but only a circulation within the biosphere, regarded in a 100 years' perspective.

The major primary and directly emitted pollutants from combustion are SO_2, NO_x, hydrocarbons, CO_2 and particulates composed mainly of carbon, silicon, iron, cadmium and nitrogen complexes.

The effects of these pollutants on the environment are several:

- effects on health (see 15.2)
- damage to vegetation and animals
- damage to soil and water
- corrosion and pollution

15.3.1.4 Localized effects on land

Much of the damage that man does to the land is successively healed over a period of time. With a conscious effort the process can be accelerated to some extent. Because of the differences in the way land can be affected and in its rate of recovery, it is difficult to compare the effects of different fuels on the land.

15.3.1.5 Environmental costs of fossil energy sources

Data of the impacts of primary energy sources and secondary energy carriers on the environment have been published (18). These data have been quantified and normalized by us to a cost unit factor per GJ of their energy contents. The air pollution costs represent damage to property and materials and increased maintenance, and the land-associated costs are reclamation costs of strip-mined land or logging areas. The results are given in Table 15-27 for the primary sources at the production site as well as for secondarily produced electricity and methanol. Electricity is assumed to be produced with a conversion efficiency of 40 % and methanol with an efficiency of 50 %. Apparently the costs for environmental burdens are about a factor of ten lower than for the health risks in connection with fossil combustion.

Table 15-27

Environmental costs, cr/GJ.

	Primary source	Electricity	Methanol
Coal	0.07	0.17	0.14
Oil	0.04	0.10	0.08
NG	0.01	0.025	0.02
Biomass	0.06	0.15	0.12
Peat	0.06	0.15	0.12

15.3.2 Nuclear electricity

Within the uranium fuel cycle there are only a few steps, apart from the health risks, which have a significant effect on the environment:

- fuel mining
- fuel refining
- cooling-water releases.

Local changes in the landscape result from the construction and operation of most plants for raw material production, and this is also the case for uranium mining. The influence is obviously very dependent on local conditions. Compared with coal production, uranium mining has a much smaller effect on the landscape.

The refining of the major Swedish uranium deposit, shale, requires sulphuric acid as a leaching agent, and this can be produced from the sulphur contents in the shale. However, some release of sulphur will occur, about 17 tons per PJ (7).

The cooling water requirements of nuclear power plants create some aquatic effects. The direct discharge of heat from a plant can significantly change the habitat in estuaries, but can also be of advantage to the society, e.g. ice-free harbours and increased fishing.

The costs due to environmental damage are estimated in the same way as for fossil fuel (18). A cost of 0.01 cr per GJ electricity is obtained.

15.3.3 Hydrogen

The only significant environmental pollutants which can be formed when using hydrogen as a fuel are nitrogen oxides. The formation of small amounts of hydrogen peroxide has been reported, but normally this can be expected to decompose rapidly in the presence of light. The dominant product in hydrogen combustion is pure water, which can be regarded as a non-pollutant substance.

When using fuel cell conversion, it is possible to eliminate most of the nitrogen oxides. In combustion, it is also possible to control the formation of nitrogen oxides by adjustment of the fuel-air mixture or by limiting the temperature.

The environmental effects of NO_x pollutants can be disregarded in comparison with other effects obtained during the production of hydrogen. These are mainly determined by the production method used. Coal gasification and electrolysis by means of nuclear produced electricity are the methods considered here. Their conversion efficiencies in the final production of hydrogen are at present approximately 50 and 80 %, respectively. Thus, using Table 15-27, the environmental costs can be shown to be 0.14 cr/GJ for coal gasification. The cost for nuclear electrolysis according to 15.3.2 is c. 0.012 cr/GJ.

15.3.4 Solar

There is no particular impact on the environment resulting directly from solar energy production. On the other hand, all the associated materials and components which have to be manufactured, plus the energy back-up, have an influence on the environment. The cost, based upon the energy back-up and the components used in the energy system, is estimated to be about 0.07 cr/GJ.

15.3.5 Wind

This can be treated in the same way as solar energy. The cost is estimated to be about three times greater than that for solar.

15.3.6 Hydroelectricity

The building of a hydroelectricity plant generally involves large-scale construction work, which produces changes in the environment. During normal operation the factors influencing the climate are in the first place temperature, smoke and moisture.

Other effects are:

- an increase in sedimentation
- an increase in the flow of water to the sea (intermittent)
- changes in the conditions for flora and fauna
- influence on the groundwater
- influence on ice formation
- an increase in erosion.

The significance of all these factors for the cost is difficult to determine. No estimates of costs have been found in the literature. Discussions with the Swedish State Power Board have shown, however, that the environmental costs are very difficult to evaluate but should be much less than those for e.g. coal and oil as energy sources (19). Starting from nuclear power, an estimate has been made:

- nuclear environmental costs are 0.01 cr/GJ (15.3.2);
- a nuclear power plant generates about twice as much energy as a hydroelectric plant;
- each hydroelectric plant is about 1.5 times as large as a nuclear plant, in other words more materials are required to build such a plant;
- more land is influenced by hydroelectricity than by a nuclear plant, say a factor of 2.

The conclusion to be drawn from the above is that the environmental costs for hydroelectricity will be about 0.06 cr per GJ.

15.4 Societal implications

A changeover from one energy system to another affects not only society but also the economic basis of society. It is not at present possible to predict the effects of such changes on the current social pattern, particulary with respect to work and housing.

The present dependence upon imported fossil fuels could have serious social effects in a situation of shortage. Many of these effects could be reduced by using an energy carrier which can be manufactured domestically, such as hydrogen.

At present our way of life is greatly dependent upon the car, but private ownership could become a luxury available only to a few because of fuel shortages or large increases in their costs and the treatment of exhaust fumes. In order to avoid such social disruptions, it is essential to have an independent fuel alternative available, such as hydrogen. The large capital investments associated with cars, such as manufacturing plants, roads, service facilities and garages, could thus be retained. The existing network for the distribution of petrol can also be modified to handle hydrogen, but several million automobile drivers as well as personnel at the service stations must be educated in the safe use of hydrogen.

15.5 Conclusions and summary

It has been necessary to make a large number of assumptions in order to produce equitable treatments for all the technologies discussed in this chapter. The most important assumptions have been outlined in this paper, but for further information the reader is referred to the references given in 15.6. Much of the basic data comes from studies made in countries outside Sweden. In most cases, they can be expected to be applicable also for Swedish conditions.

The most important conclusion to be drawn from this study is that the risks from non-conventional energy sources are usually significantly greater than those from conventional sources (Table 15-28, Figure 15-2). The lowest health and environmental costs are apparently obtained for nuclear electricity, natural gas and hydrogen.

This is in agreement with some other investigations where the risks of hydrogen have been compared to those of some other fuels, mainly natural gas and petrol. The environmental effects were found to about equal for hydrogen and NG.

Table 15-28

Risk costs for energy carriers.

Type of energy	Risk, man-years lost per PJ	Health cost cr/GJ	Environment cost cr/GJ
Coal			
electricity	9 - 159	1.50	0.17
hot water	4 - 73	0.70	
methanol	48 - 807	7.90	0.14
Oil			
electricity	4 - 128	0.90	0.10
hot water	2 - 62	0.45	
petrol	3 - 192	0.95	0.10
Diesel	3 - 151	0.85	
Natural gas			
primary source	0.5 - 2.7	0.05	0.01
electricity	1 - 7	0.10	0.025
hot water	0.7 - 3	0.05	
Nuclear			
electricity	1 - 11	0.15	0.01
hot water	0.4 - 4	0.05	
Biomass			
electricity	17 - 169	2.15	0.15
hot water	8 - 80	1.00	
methanol	140 - 1328	17.50	0.12
Peat			
electricity	17 - 169	2.15	0.15
hot water	8 - 80	1.00	
methanol	101 - 1179	13.80	0.12
Hydrogen gas			
coal gasification	8 - 129	1.30	0.14
electrolysis, nuclear electricity	2 - 16	0.25	0.01
Solar			
thermal electricity	64 - 128	3.60	0.07
photovoltaic electricity	117 - 175	5.70	
hot water	156 - 202	7.10	
Wind power, electricity	449 - 638	21.40	0.20
Hydroelectricity	72 - 78	3.00	0.06

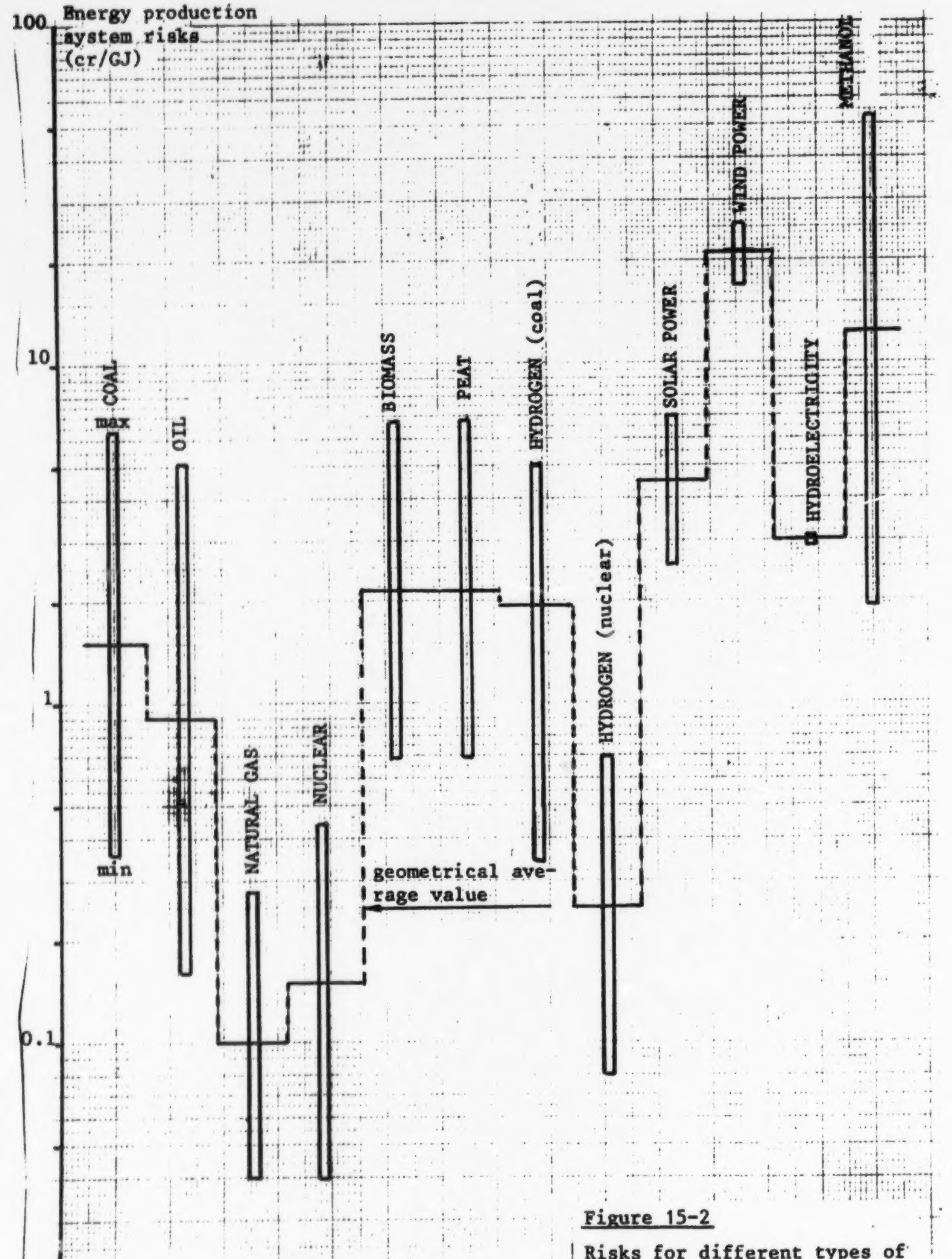

Figure 15-2

Risks for different types of electrical energy production compared to those of hydrogen and methanol.

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16. CONCLUSIONS

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The aim of the study has been to try to assess the future market for hydrogen in Sweden during the next 50 years. This period must be regarded as having more inherent uncertainties, with regard to the development of the general economic situation and of the supply situation for primary and secondary energy sources, than have ever been met with before. A totally new energy supply picture can be expected to evolve during the period, and this will probably have to be achieved within a stagnating or only slowly expanding economy. We have tried to solve the dilemma by introducing three different, fixed energy scenarios, all of a rather extreme nature, within the same general economic scenario and by working with the same fuel cost scenario. The uncertainties in these calculation examples are already very great, and we have not considered it worth-while to estimate variation limits for new cost figures and market penetrations.

Another factor which further limits the reliability of the results consists of the restrictions according to Chapter 2 that have been applied throughout the study. The assumption that coal will be of small importance as an energy source does not appear to be valid any longer. Coal is instead today regarded as one of the principal primary alternatives for the future Swedish energy supply. A large import of coal might considerably change the competitive structure set-up of the scenarios and the conclusions drawn in the study.

A large-scale introduction of hydrogen into the Swedish energy supply system requires a considerable change in the infrastructure of the country. The necessary demand must first be created, the customer has to become accustomed to the new energy carrier and taught to use it, and technological changes must be accomplished and adapted down to customer level. All these factors require a long time. Since in addition hydrogen is of minor importance for the chemical industry of today, it seems hardly likely that hydrogen will be in general use before the turn of the century. The study has therefore been concentrated to the years 2005 and 2025.

16.1 Production, storage and transmission

Electrolysis is the most likely method to be applied for the domestic large-scale production of hydrogen in Sweden. According to the demand forecast, the first production plant of the assumed reference size of this study (annual production 0.14 Mton) can be expected to be taken into operation in the late nineties at the earliest. A probable choice for the first generation of plants is SPE electrolysis, which will in all probability be sufficiently developed by that time to be applicable for this purpose, and which according to our cost calculations has competitive advantages over advanced alkaline electrolysis. A second generation may possibly instead use high temperature electrolysis in solid oxide systems, being adopted first towards the end of the period.

Biomass, peat and organic wastes are indigenous fuels which can be used as raw materials for hydrogen production. Rough calculations, which are subject to great uncertainties, show that the production cost is likely to be slightly less than for electrolytic hydrogen. If this is the case, these fuels are a likely choice in scenario B. The commercial application of direct thermal or closed thermochemical water splitting appears more far-fetched, but it might be possible at the end of the period. The expected costs are of the same magnitude as those above, i.e. 60±10 cr/GJ GH_2. Photochemical methods, bioconversion and the application of high energy radiation are all highly improbable production methods, either due to difficult technical problems or to a very unfavourable economy.

Table 16-1 summarizes production costs for GH_2 according to alternative routes as well as the same costs for alternative energy carriers. Conventional GH_2 methods, i.e. steam reforming of NG and coal gasification, have been included for comparison, despite the fact that their applications are prohibited because of the restrictions of this study. It is apparent from the table that electrolysis and other new methods are successively gaining competitiveness against the conventional methods, but that the cost of coal gasification will still be outstandingly low at the end of the period.

Table 16-1

Fuel production (import) costs.

Energy carriers	Costs cr/GJ		
	1985	2005	2025
Natural gas	12.0	23.0	38.3
Synth. natural gas	15.7	23.5	34.0
Petrol	22.2	36.5	61.4
Synth. petrol	39	51	62
Methanol (import)	30	43	52
Methanol (biomass)	55	58	60
Electricity	28.0	39	54
GH_2 (electrolysis)	42.5	51	62
LH_2 (electrolysis)	53	64.5	80
GH_2 (biomass)	43	47	51
GH_2 (steam reforming)	19.6	34.3	54.5
GH_2 (coal gasification)	22.3	27.5	35

Hydrogen can be stored as a compressed gas or in liquid form at a very low temperature, -253°C. Large storage capacities will be necessary in order to neutralize differences between production and consumption.

For Sweden, it is anticipated that the following storage alternatives are potentially possible and economically competitive:

- Underground, in gaseous form, in geologically formed aquifers.
- Underground, in gaseous or liquid form, in unlined or lined rock caverns or in containers located in rock caverns.
- Above ground, as a liquid, in large, cryogenic containers.

Suitable aquifers for large-scale storage can be expected to be found at many places in southern Sweden. In regions where conditions for geological storage do not exist, there are good chances of finding hard rock convenient for excavated rock caverns.

The storage of LH_2 in rock caverns is an extremely complex technical problem, judging by the difficulties which have been met by engineers and researchers during the development of methods for the storage of liquefied natural gas in facilities of this type. Comprehensive research, development and design work must be carried out before they can be brought into operation.

Table 16-2 summarizes the storage costs for facilities connected to a reference production plant for hydrogen. It is assumed that a storage volume of 1/10 of the annual plant capacity, 0.14 Mton H_2, is required. The costs for the storage of alternative energy carriers are included for comparison purposes in the appropriate columns.

Table 16-2

Storage costs for alternative energy carriers calculated as 1/10 of the real annual costs, cr/GJ.

Storage method	Hydrogen	Natural gas	Petrol	Methanol
Geological	0.8	0.28		
Unlined, uninsulated rock cavern	1.65	0.55	0.05	
Lined, insulated rock cavern (liquid)	1.2			0.17
Unlined, insulated rock cavern (liquid)	1.0	0.32		
Tanks above ground (liquid)	0.95	0.31	0.10	0.21

Hydrogen can be transmitted and distributed to the final customer either as a gas through a compatible pipeline system, or as a cryogenic liquid by lorry or rail. The costs for the transmission of large bulk quantities of hydrogen in the form of solid hydrides or as highly compressed gas by lorry or rail are completely prohibitive.

Experience from operating systems has shown that large natural gas pipelines can be safely converted to the transmission of hydrogen, at least if the original system was constructed from low-strength steel, was seamlessly welded and was carefully laid out with only very minor leaks. New compressors must be installed in order to compensate the lower volumetric heat content of the hydrogen gas by a higher throughput. It is not advisable to increase the gas pressure above that commonly used for NG, i.e. $\leq$ 8 MPa, because of material compatibility. For the same reason, the gas temperature must also be restricted, and should preferably be ambient. The transition to hydrogen transport is facilitated if the original pipeline system is built with this in mind. This could be the case for Sweden, where at present no NG distribution system exists.

Transmission costs for GH_2 in pipelines and LH_2 by lorry or rail are summarized in Table 16-2 and compared to those of alternative energy carriers.

Table 16-3

Transmission costs for alternative energy carriers in cr/GJ.

Energy carrier	Transmission distance, km		
	100	200	500
GH_2 (pipeline)	0.6	1	2.4
LH_2	5	7	11
NG and SNG (pipeline)	0.4	0.7	1.3
Petrol	0.5	1.8	2.2
Methanol	1.0	1.4	4.5
Electricity	7.2	8	10.8

It can be anticipated that metals will be the most important structural materials in all manufacturing processes and applications of gaseous or liquid hydrogen. Experience has shown that hydrogen can be safely handled and used if material qualities and specifications are set according to the special properties of the element and the prevailing conditions. Research on structural materials will probably continue in two different directions, namely the validation of existing materials and the standardization of test procedures on the one hand, and a search for new inexpensive materials, including protective coatings, on the other.

16.2 Safety, environmental and societal aspects

Consideration of future hydrogen applications reveals no insurmountable problems in the industrial and commercial market, as long as prescribed safety rules are rigorously followed and the equipment is handled by well trained personnel. Excellent safety records have been maintained in Germany during more than 40 years' use of an industrial gas piping system, as well as by NASA in its use of vast quantities of LH_2 in the US space program. Safety problems may arise in connection with transport and in the residential fuel market, where the general public experiences a more direct contact with hydrogen. This is particularly the case if LH_2 is used as a common car fuel. Stringent safety rules would have to be set up. GH_2, on the other hand, has been in common use for a long time as an admixture to town gas without either perceptible negative consequences for society or public objections. From a logical point of view, it seems reasonable that fuel availability and cost would outweigh fuel safety in a choice between hydrogen and alternative fuels in the future.

However, public perception of the safety of hydrogen may be one of the major obstacles to a transition to a hydrogen economy. Perception of "unreal" hazards are based on incomplete knowledge, the novelty of the technology and contradictory information from so called experts, and they can be further influenced by pure psychological and scare factors. The greatly overdramatized Hindenburg accident, when in fact 65 people survived out of a total of 123 on board the Zeppelin, is in public eyes identified with a major catastrophe caused by the exceptionally dangerous substance hydrogen.

There is no point in denying the danger implicit in the widespread use of hydrogen. Compared to NG, GH_2 is much more prone to leak, can be ignited by extremely low quantities of energy and is flammable and explosive over a wide range of hydrogen-air mixtures. In liquid form, its low temperature can liquefy any air in contact with it, which produces highly explosive mixtures. Furthermore, the gas is colourless and odourless, and burns with an almost invisible flame.

The damning list of negative properties is partly counter-balanced by the high buoyancy and diffusitivity of hydrogen. A leak therefore seldom leads to a concentration sufficient to sustain ignition and, unlike petrol, methanol and NG, hydrogen very rapidly departs from the scene of spills and leaks.

All energy carriers which are expected to provide Sweden with energy in the future are associated with health and environmental risks but of greatly varying intensities. In all applications considered here, electricity and hydrogen must be regarded as outstanding compared to their competitors. Electricity does not give rise to any pollution at all. The only products obtained, besides water, when hydrogen is combusted in air are minor amounts of nitrogen oxides which are also formed when alternative energy carriers are combusted. The formation of NO_x can be completely avoided by combustion in oxygen, by limiting the temperature or by the use of fuel cells. However, environmental and health problems of major importance, which are similar to those posed by their competitors, exist during the production, storage and transmission of electricity and hydrogen.

An attempt has been made to quantify the total societal implications arising from the use of all the secondary energy carriers considered here, as well as their primary energy sources. The analysis was carried out for the complete fuel cycle from the original production (mining) up to the final application. Risk factors were calculated for health, other environmental aspects (including costs due to accidents) and societal implications, and these were transformed to a cost factor. Health risk factors were obtained from published literature. A deductive method was used in order to calculate the other environmental implications. For the present, no method has been found of transforming societal implications into cost figures of any reliability.

The results of the assessment are given in Table 16-4 for the principal alternative energy carriers, together with their production costs according to Table 16-1. The total costs are shown in the last column. It is apparent that the addition of environmental costs has no effect at all on the earlier cost picture, except for methanol. It should be noted that the uncertainty in the risk costs is very large. The original risk values taken from literature and used for the calculations have also been strongly critized recently; even their orders of magnitude have been questioned. The total costs given in the table have therefore not been used in the market analysis of the applied sectors.

Table 16-4

Risk costs for alternative energy carriers in cr/GJ in 2025.

Energy carrier	Health costs	Other env. costs	Production costs	Total costs
NG	0.05	0.01	38.3	38.4
Petrol	0.95	0.10	61.4	62.5
Methanol from				
coal gasification	7.9	0.14	52.0	60.0
biomass	17.5	0.12	60.0	77.6
Electricity, nucl.	0.15	0.01	54.0	54.2
GH_2				
electrolysis, nucl. electricity	0.25	0.01	62.0	62.3
coal gasification	1.30	0.14	35.0	36.5

16.3 Application sectors

For the different application sectors, the result of the market assessment is summarized in 16.5 in the form of anticipated demand figures within given energy scenarios.

The necessary annual investment capital required to achieve the anticipated demand for hydrogen is discussed in 16.6 together with its implication on Sweden's economy.

16.3.1 Chemical industry

Currently, hydrogen has a very limited use as a raw material or as a fuel in the Swedish process industries. The annual consumption as a raw material is about 35000 tons, and this is mainly used for the synthesis of ammonia and various organic compounds, for the hardening of fats and for petroleum refining. Most of the captive hydrogen generated in petroleum refining operations is consumed as a fuel (160000 tons annually).

The market investigation shows that the consumption of high-energy gases (NG, GH_2 or a mixture of these) as feedstocks is unlikely to increase significantly during the period. If special conditions are created for ammonia and methanol industries, for example by a national policy providing a strong element of stimulus or protection or by a large-scale exploitation of Swedish shale deposits containing uranium, the use of hydrogen could exceed 0.2 Mton in about 25 years' time. In an open, non-protected economy this is not likely to be the case. The pipe grid for NG/SNG/GH_2, which is assumed to be built in the nineties according to scenario C, would constitute a favourable pre-requisite for indigenous ammonia/methanol plants, particularly towards the later part of the period studied, when gasification plants based on bio-materials could also have been phased into the supply system. It is, however, less probable that pure hydrogen would be fed into the grid in anything but marginal quantities.

The total consumption of fuels in chemical process industries is expected to increase almost 50 % in 50 years. A large part of the market increase may be covered by merchant high-energy gases where GH_2 is one alternative. Penetration of the market will be particularly favoured if a national gas piping system as in scenario C is introduced. It is anticipated here that the maximum market share in 2025 will be ca 45 % in scenario C and ca 15 % in scenarios A and B, the total annual fuel consumption being 156 PJ.

The results of the assessment are summarized in Table 16-5. The variations are due to the policy-dependent production of ammonia and methanol and to the competition between GH_2 and NG/SNG as a heat source, as have been discussed above.

Table 16-5

Hydrogen consumption in the chemical sectors, PJ/year.

Year	1978	1985	2005		2025	
Scenario		A, B, C	A, B	C	A,B	C
Sector						
Chemical	3.5	5	2 - 8	2 - 8	3 - 10	3 - 10
Petro-chemical	1.5	3	4	4	3	3
Syn. fuel		0 - 4	0 - 18*	0 - 18	0 - 18*	0 - 18
Ind. heating	23.5	33	36 - 52	36 - 72	18 - 43	18 - 91
Total	28.5	41 - 45	42 - 82	42 - 102	24 - 74	24 - 122

* In scenario A 5 PJ

16.3.2 Metallurgical industry

Possible future reductants for Swedish iron ores and raw steels are coke, coal, charcoal, biomass and hydrogen. If the present production structure is maintained, that is if the iron and steel industry continues to produce semi-finished, standardized products in large units, it is very unlikely that hydrogen reduction can compete with the other alternatives.

If instead the production structure is successively altered towards an integration of the ore reduction with the refining of raw steel to finished products, it becomes essential that the reduction process should be fast and should require only small investments. In addition, the pollution problem must be easy to handle, and it will be advantageous if the process can be turned on and off intermittently during daytime. All these requirements can be met by a plasma process with hydrogen as reductant. Other reducing agents, e.g. coal, have been found to be less competitive.

The proposed plasma process has the following advantages: Advantageous to operate on a small scale, low investment costs, a rapid process, possibilities for intermittent operation, low pollution and low generation of steel scrap. The main disadvantage is a comparetively high production cost, but this can be partly compensated for by a changeover to more valuable final products. Labour union demands for a transition from shiftwork to daytime work may force the industry to adopt processes which are better suited for intermittent operation.

Throughout the period, the annual production of steel is anticipated to remain at about the same level as the average during the seventies, i.e. 5 Mtons. In 2025, half of this amount is assumed to be produced according to present techniques and the other half in small-scale operations with plasma reduction, using hydrogen as the reductant. The introduction of the new technique is assumed to start in 1990 and to proceed at an even rate until the year 2025. The expected hydrogen consumption has been calculated to be 6.2 and 14.5 PJ/year in 2005 and 2025, respectively. The necessary investments for the transition are well within the limits of present-day figures for the renewal of existing equipment and the maintenance of existing capacity, i.e. about 1 Gcr/year.

Hydrogen may also be used for the reduction of metals other than iron. However, the demand can be expected to be negligible compared to the demand within steel production.

16.3.3 Peak power generation

About 8 % of the electric energy in Sweden today is produced in stations with average annual utilization times of less than 2000 hours. Most of this is produced in fossil fuelled condensing power plants. Only about 0.1 % of the electricity demand is produced in extreme peak power stations, i.e. gas turbine or Diesel plants. Hydrogen can be used for peak power production in gas turbines or fuel cells, either of a storage or a non-storage type.

A complete breakdown of costs as a function of the utilization time was performed comparing hydrogen and conventional methods, including pump power stations. The fuel cell efficiency was assumed to be 60 % in 2025 and the hydrogen gas turbine efficiency to be 50 %. The result shows that fixed annual costs are of the same magnitude with a few exceptions, but that running costs for pump power are very much lower than those for the other methods which are mutually more comparable. It can be concluded that hydrogen peak power cannot compete with pump power until its efficiency can be raised above that of pump power, i.e. 80 %, which is impossible to expect during the period. Environmental and societal effects cannot compensate for the very large economic disadvantages.

Except for very special purposes and hence in limited amounts, hydrogen cannot be expected to be used for peak power production during the period studied.

16.3.4 Residential and commercial heating

Residential heating presupposes that a national gas piping system has been constructed, covering large population centres and similar to that prescribed in scenario C. Heating with evaporating LH_2 is out of the question. Hydrogen for industrial heating can be supplied from an internal or local grid system similar to that which it is anticipated will be developed in some chemical industries (16.3.1).

A suitable technique for the application of hydrogen burners can be expected to be fully developed in the nineties; it should be possible to overcome the safety problems which arise. Hydrogen can either be burnt directly or used to fuel a heat pump engine. Heat pumps have the advantage that they generate more useful heat than is generated by the direct burning of the same amount of fuel.

Conventional heating methods have been compared with the hydrogen alternative, both for residential heating in separate furnaces for each house and for district heating to private homes as well as to large residential or commercial buildings. Fuels such as oil, NG, methanol, electricity and biomass have been compared to hydrogen. The following conclusions have been drawn:

- In scenario A, hydrogen cannot compete with the low costs of electric heat pumps which are expected to become the dominating heating instrument. This technique can also be expected to be too well established at the time when there are appropriate prerequisites for the introduction of hydrogen driven heat pumps.
- In scenario B, hydrogen heating is an interesting alternative with costs competitive with those of other allowed methods. The market share is estimated to be 5 PJ in 2005 and 50 PJ in 2025 because of the slowness of the introduction process.
- In scenario C, hydrogen can hardly compete with much cheaper SNG which in the scenario is allowed to be imported in unlimited amounts and has a finished distribution system. Governmental actions such as special taxes due to environmental considerations could change this picture.

16.3.5 Transportation

An approach deviating from that applied in the other market sectors has been used for the assessment of the future transportation market. Five alternatives have been suggested with different mixtures of propulsion and fuelling systems, which are all judged to be probable within given scenarios. The total costs to society of each alternative have been evaluated as a function of the time span and related to a "spontaneous" development case which represents an extrapolation of the present conventional technology, with battery powered electric vehicles for town traffic being slowly introduced into the market in the beginning of the nineties. The evaluation comprises all types of road traffic, car manufacturing and the complete fuelling systems. The fuel consumption has been calculated in view of expected energy efficiencies of the different fuel systems and car types.

About 30 % of the total Swedish supply of energy for transports is consumed by a heterogeneous group of vehicles, for instance international and military transports, agricultural and lumbering machinery, and small boats. These categories are not likely to convert to new fuel systems during the period and are therefore not included in the cost calculations of the alternatives conceived.

For the chosen case with a fast introduction of hydrogen, the annual extra costs reach a maximum of about 2.5 Gcr by comparison with the spontaneous case in the middle of the period, and they actually become negative during the last 10 years. The similar methanol case has a similar development. On the other hand, battery driven cars give rise to successively increasing negative extra costs from the moment of their introduction.

It is evident from the above that in scenario A, where the supply of electricity is ample, hydrogen can hardly compete with electricity. In scenario B on the other hand, hydrogen appears to be advantageous but competes with almost equally favourable methanol. Even in scenario C, where petrol is available in unlimited amounts, a slow introduction of hydrogen might lead to economic advantages.

The anticipated total fuel consumption in Sweden for each of the chosen alternatives is summarized in Table 16-6. The figures given include all types of land, sea and air transports. The petrol column represents all conventional hydrocarbon fuels.

Table 16-6

Fuel consumption in the transport sector, PJ.

Alternative case	2005				2025			
	petrol etc.	methanol	GH_2	electricity	petrol etc.	methanol	GH_2	electricity
El. battery	348			20	317			31
High H_2	265		71	17	150		135	28
Methanol	253	107		15	132	182		24
Spontaneous	387			16	360			27
Low H_2	380		4	15	330		16	25

16.4 Calculated total hydrogen demand

The total demand for hydrogen according to the market analysis performed is given in Table 16-7. The sectors specified are those which have been agreed upon within the IEA Study Group; the table also shows the three energy scenarios A - C which have been developed for this study. It must be emphasized that the uncertainty in all the figures for 2005 and 2025 is very large, and that they can only be regarded as reasonable estimates on the basis of the assumptions given in the introductory chapter and/or discussed in the sections on applications. Where the figures in the columns are given as ranges, these depend on policy-dependent factors in the chemical industry (16.3.1.) and the choice of alternative in the transportation sector (16.3.5.).

Table 16-7

The Swedish hydrogen market in PJ/year.

Market sectors	Actual market 1978	Estimated demand						
		1985	2005			2025		
		A,B,C	A	B	C	A	B	C
Non Energy								
Chemical	3.5	5	2 - 8	2 - 8	2 - 8	3 - 10	3 - 10	3 - 10
Metallurgy	-	-	6	6	6	15	15	15
Energy Indirect								
Petrochemical	1.5	3	4	4	4	3	3	3
Synfuel	-	0 - 4	0 - 5	0 - 18	0 - 18	0 - 5	0 - 18	0 -18
Peak power	-	-	-	-	-	-	-	-
Energy Direct								
Space heating	-	-	-	5	-	-	50	-
Process heat*	23.5	33	36 - 52	36 - 52	36 - 72	18 - 43	18 - 43	18 - 91
Ground transp.	-	-	-	0 - 71	0 - 4	-	0 - 135	0 - 16
Air transp.	-	-	-	-	-	-	-	-
Total	28.5	41 - 45	48 - 75	53 - 164	48 - 112	39 - 76	89 - 274	39 - 153

* The lower figure internally generated hydrogen.

16.5 Investment requirements

The average annual Swedish investment capacity has been estimated in Table 3-6. These gross investments are as follows, where the figures refer to Gcr at the 1978 value:

	1985	2005	2025
Commercial and industry	71	94	124
industry only	17	21	26

The investments for a future large-scale production and application of hydrogen can only be allowed to appropriate a small fraction of the total available investment capacity, certainly less than 5 %. For the time periods 1995 - 2005 and 2005 - 2025, estimates have been made of the required average annual investments. The results are collected in Table 16-8. For each of the three scenarios A - C, the figures are based on the maximum demand values given in Table 16-7 after deducting internally generated hydrogen. Only investments that are necessary in order to achieve the anticipated hydrogen economy are included in the figures. Investment capacity resulting from normal industrial capital renewal is not included. Investments earlier than 1995 are regarded as negligible.

For each of the observed sectors, the following assumptions are valid:

- Hydrogen is produced as GH_2, by SPE electrolysis in scenarios A and C and from biomass in B. Investment costs for the primary source are included in the figures. The required number of production plants of the reference size (0.14 Mton/year) is

	2005	2025
A	2	3
B	7	13
C	4	7

- Hydrogen is stored as GH_2 in aquifers, the required volume being 1/10 of the annual capacity. Investment costs are 60 cr/GJ H_2.
- Hydrogen is transmitted by a national gas pipeline system at 5 MPa. The network has a total length of 2000 km and is successively constructed during the period 1995 -2025, except in scenario C where an NG net suitable for GH_2 is assumed to exist already in 1995. Specific investments are 500 Mcr per 200 km. Residential heating requires an added distribution network of 500 km length with a total cost of 800 Mcr.
- In the chemical sector, investments are made within the available normal investment capacity.
- The same is also valid for the metallurgical sector.
- Residential heating requires capital investments of 600 Mcr/PJ, excluding the distribution network.
- For the transport sector, average annual costs in excess of the "spontaneous" development case are 2.5 Gcr in scenario B and 0.4 Gcr in scenario C for the period 1995 - 2005, and 2.2 Gcr in scenario B and 0.6 Gcr in scenario C for the period 2005 - 2025.

In all the scenarios, the required investment capital lies well within the compass of the available national gross investment sum.

Table 16-8

Average annual investments in Gcr for the period 1995 - 2025.

Sector	1995 - 2005			2005 - 2025		
	A	B	C	A	B	C
Production	1.0	0.6	2.0	0.25	0.3	0.75
Storage	0.02	0.08	0.05	0.01	0.05	0.02
Transmission	0.3	0.3	0.1	0.3	0.35	0.1
Chemical industry	-	-	-	-	-	-
Metallurgical industry	-	-	-	-	-	-
Residential heating	-	0.3	-	-	1.4	-
Transportation	-	2.5	0.4	-	2.2	0.6
Total	1.35	3.8	2.55	0.55	4.3	1.5

16.6 Anticipated energy scenarios

The total demand for hydrogen in the various energy scenarios A, B and C is summarized in Table 16-7. The resulting total demands are expressed as ranges with a minimum and a maximum value. The final energy scenarios will therefore be specified for two different levels of hydrogen demand, corresponding to a "low H_2" and a "high H_2" case.

In all the scenarios, an internal hydrogen production of 36 PJ (year 2005) or 18 PJ (year 2025) per year is anticipated for the chemical industry. The resulting requirements for the supply of hydrogen have therefore been reduced somewhat by comparison with the figures given under "total" in Table 16-7.

Some departures have been made from the general assumptions about the growth of the energy demands in various sectors according to Chapters 3 and 4. This is particularly true for the transportation sector, for which a more rapid growth of the demand was deducted than that originally anticipated for the period up to the year 2005. Around this year the demand levels out to a constant value and finally it decreases somewhat during the last part of the period studied. The total demand for the year 2025 is therefore the same as that assumed in the scenarios in Chapter 4. The development of transportation work is also in agreement with the original assumptions, but the introduction of energy saving technique is assumed to be on a larger scale during the period after 2000 than before. The demand for electricity rail-bound traffic has been reduced.

In the chemical sector, hydrogen replaces electricity for the production of process heat in scenario A, and in the same way it replaces biomass and heavy fuel oil for the production of process heat in scenarios B and C, respectively.

The hydrogen in the residential sector in scenario B is used for the operation of large heat pumps in district heating systems. This technique replaces to some extent the burning of light fuel oil in 2005 and the burning of wood fuel in 2025.

Hydrogen is assumed to be produced by electrolysis in scenarios A and C. The efficiency of the electricity-to-hydrogen conversion process is assumed to be 86 % in 2005 and 97 % in 2025. In scenario B, hydrogen is produced from biomass with a corresponding biomass-to-hydrogen conversion efficiency of 45 % (in both 2005 and 2025).

The energy required for hydrogen production is met by additional nuclear power plants in both scenarios A and C. A heavy introduction of nuclear power plants in scenario C is not in particularly good agreement with the basic premises for this scenario (cf 4.4). A more consistent method of producing hydrogen would have been with coal as the primary energy source for the direct production of hydrogen. A greater import of coal is not, however, in agreement with the assumptions of the study. Alternatively, imported gas (NG or SNG) could be used as a raw material for the production of hydrogen.

The increased demand for biomass in scenario B is assumed to be covered by domestic production, but it must be emphasized that a very successful development of the energy plantation technique is a necessary prerequisite for the required high production volume.

The final energy supply for the scenarios with hydrogen introduced into them is summarized in Table 16-9. This table together with Table 1-4 gives an impression of how, in the different scenarios, domestic production and use of hydrogen could affect the total supply to the Swedish energy system.

Table 16-9

Total energy supply for the scenarios with hydrogen introduced into them, PJ.

	Scenario A				Scenario B				Scenario C			
	2005		2025		2005		2025		2005		2025	
	low H_2	high H_2	low H_2	high H_2	low H_2	high H_2	low H_2	high H_2	low H_2	high H_2	low H_2	high H_2
FUELS												
Uranium	1662	1744	2953	2947	582	582	610	610	664	885	721	1070
Coal and coke	131	131	116	116	209	209	204	204	120	120	105	105
Light fuel oil and Diesel	156	142	0	0	83	83	0	0	104	104	86	86
Heavy fuel oil	236	203	78	57	145	135	88	67	596	566	699	634
Petrol and jet fuels	154	117	39	39	131	131	44	44	119	119	39	39
Natural gas and SNG	-	-	-	-	-	-	-	-	162	162	237	237
In situ wood fuels	150	150	158	158	140	140	140	140	155	155	155	155
Synthetic fuels	52	39	200	33	-	-	-	-	158	151	243	213
Peat	-	-	-	-	212	212	367	367	-	-	-	-
Biomass	-	-	-	-	501	747	1102	1334	-	-	-	-
	2541	2526	3544	3350	2003	2239	2555	2766	2078	2262	2285	2539
DIRECT ELECTRICITY (based on renewable sources)												
Hydro	256	256	256	256	256	256	256	256	256	256	256	256
Wind	44	44	64	64	60	60	110	110	40	40	64	64
	300	300	320	320	316	316	366	366	296	296	320	320
Total	2841	2826	3864	3670	2319	2555	2921	3132	2374	2558	2605	2859